BOARD STAFF INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Ex. E1 /Tab 2/ Sch 1 / para 5

The section speaks to the $700 credit facility for the peak gas storage cycle.

Please provide a detailed description of how this facility operates in practice. Please discuss the rates and costs of the facility, the benefits of this facility vs. any alternatives, and how it affects the Company's cost of capital.

RESPONSE

Please see the response to CME, CCC, SEC, VECC Interrogatory 2, filed at Exhibit I, Issue E1, Schedule 21.2.

Witnesses: R. Fischer
M. Lister
D. Yaworski

BOARD STAFF INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Ex. E1 /Tab 2/ Sch 1 / para 21

The long term debt rate for 2013 is referenced as being 5.90%. Please update this rate as necessary to reflect current market rate expectations for 2013.

RESPONSE

Please see the response to Energy Probe Interrogatory 1, filed at Exhibit I, Issue E1, Schedule 7.1.

Witnesses: R. Fischer
M. Lister
D. Yaworski

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Exhibit E1, Tab 2, Schedule 1

a) Please confirm that the figures in Table 1 reflect all actual data for 2011. If this cannot be confirmed, please update Table 1 to reflect actual data for 2011.

b) Please provide the Canadian Deposit Offer rates and the company specific spreads used to derive the numbers shown in the table in paragraph 16. Please also update the table to reflect actual 2011 data.

c) Please update the table found in paragraph 16 to reflect the most recent forecasts available for 2012 and 2013. Please show the breakdown of the components of the forecast in the same format as requested in part (b) above.

d) Please provide the Government of Canada bond rates and the company specific spreads used to derive the numbers shown in the table in paragraph 21. Please also update the table to reflect actual 2011 data.

e) Please update the table in paragraph 21 to reflect the most recent forecasts available for 2012 and 2013. Please show the breakdown of the components of the forecast in the same format as requested in part (b) above.

f) Please explain the difference in the 41.9% shown in Table 4 to the 42% noted in paragraph 2.

RESPONSE

a) Confirmed.

Witnesses: K. Culbert
M. Lister
D. Yaworski

b) The following table provides the composition of the short term debt rates as presented:

	2011	2012	2013
3-Month CDOR	1.60	2.40%	3.50%
Spread	0.10%	0.10%	0.20%
Short Term Debt Rate	1.70%	2.50%	3.70%

The following table provides the composition of the short term debt rates using the 2011 actual CDOR rate and updated to reflect the latest forecast for 2012 and 2013:

	2011	2012	2013
3-Month CDOR	1.29%[1]	1.40%	1.90%
Spread	0.10%	0.10%	0.10%
Short Term Debt Rate	1.39%	1.50%	2.00%

[1] Represents the average annual actual rate

c) Please refer to response to above.

d) The following table provides the composition of the long term debt rates as presented:

	2011	2012	2013
10-year Government of Canada Bond Yield	3.30%	3.80%	4.20%
Spread	1.05%	1.00%	1.00%
Long Term Debt Rate	4.35%	4.80%	5.20%

Witnesses: K. Culbert
M. Lister
D. Yaworski

The following table provides the composition of the long term debt rates using the 2011 actual CDOR rate and updated to reflect the latest forecast for 2012 and 2013:

	2011	2012	2013
10-year Government of Canada Bond Yield		2.40%	3.00%
Spread		1.10%	1.10%
Long Term Debt Rate	4.98% [1]	3.50%	4.10%

[1] Represents the coupon associated with the $100 million, 39 year MTN issued in 2011

e) Please refer to response to above.

f) The common equity ratio of 41.90% shown in Table 4 of Exhibit E1, Tab 1, Schedule 1 is the Company's overall requested equity ratio, inclusive of CIS/Customer Care capital requirements already approved in EB-2011-0226. Within EB-2011-0226, an equity ratio of 36% was set for CIS/Customer Care capital requirements. The common equity ratio of 42% referenced in Exhibit E1, Tab 2, Schedule 1, paragraph 2 is the Company's requested equity ratio for all other capital requirements, exclusive of CIS/Customer Care requirements. The combination of CIS/Customer Care capital requirements utilizing a 36% equity ratio, and all other capital requirements utilizing the requested 42% equity ratio, results in an overall equity ratio of 41.90%.

Witnesses: K. Culbert
M. Lister
D. Yaworski

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

E – Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Exhibit E1, Tab 2, Schedule 1 &
Exhibit E1, Tab 1, Schedule 1

a) How has EGD forecast the cost associated with preference shares that rise from 2.48% in 2011 to 3.28% in 2012 and to 4.16% in 2013?

b) Please update the forecasts for 2012 and 2013 noted above to reflect the most recent forecasts available.

RESPONSE

a) In July 2009, the holders of EGDI's preferred shares elected a floating rate calculation for dividend payments. As a result, the dividend rate is re-set quarterly at 80% of the average Canadian prime lending rate offered by Bank of Montreal and Toronto-Dominion Bank. The forecast dividend rate is based on the following forecast of the Canadian prime lending rate:

	2011	2012	2013
Canadian Prime Lending Rate	3.30%	4.10%	5.20%

b) The following reflects the Company's latest forecasted rates for 2012 and 2013:

	2012	2013
Canadian Prime Lending Rate	3.40%	4.00%

Witnesses: K. Culbert
M. Lister
D. Yaworski

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

E – Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Exhibit E1, Tab 1, Schedule 1 &
Exhibit E3, Tab 1, Schedule 2 &
Exhibit E4, Tab 1, Schedule 2

a) Please explain why the $138.8 million in long-term debt interest shown in Table 4 of Exhibit E1, Tab 1, Schedule 1 is higher than the figure of $137.7 million shown in Exhibit E3, Tab 1, Schedule 1 for the test year.

b) Please explain why the $138.7 million in long-term debt interest shown in Table 3 of Exhibit E1, Tab 1, Schedule 1 is lower than the figure of $140.1 million shown in Exhibit E4, Tab 1, Schedule 1 for the bridge year.

RESPONSE

a) The $138.8 million of long term interest shown in Exhibit 1, Tab 1, Schedule 1, Table 4 includes the effect of the approved CIS asset within the overall capital structure and rate base of $4,190.8 while the $137.7 million shown in Exhibit 3, Tab 1, Schedule 1 is the interest expense for all other utility rate base of $4,120.3 million, exclusive of the approved CIS asset. Evidence in Exhibit D1, Tab 12, Schedule 1, explains the required separate treatment and impact of the CIS/Customer Care approved amounts within the overall revenue requirement and resulting deficiency.

b) Within the regulatory construct of recovering costs of capital, the recovery of the amortization of debt issuance costs and discount/premiums is treated within the capital structure required overall return and is eliminated from being an income statement recovery treatment. As shown in Exhibit E4, Tab 1, Schedule 1, page 2, the calculation of the annual long and medium term cost rate of 5.89% uses effective interest rates associated with each debt issuance shown at Exhibit E4, Tab 1, Schedule 2, which take into account the issuance related costs and

Witness: K. Culbert
D. Yaworski

discounts or premiums, instead of the coupon rate related to each issuance. In order to recover the annual interest and rolling annual amortization of debt discount within the capital structure treatment, the average effective debt rate is applied to total average outstanding debt net of the average unamortized debt discount and expense balance.

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

E – Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Exhibit E3, Tab 1, Schedule 2

a) Can EGD redeem any of the long term debt issues shown in Schedule 2 before their maturity date? If yes, please identify which issues can be redeemed prior to their maturity date.

b) If the response to part (a) is yes, what is the cost of any penalties or other costs associated with each of the issues that can be redeemed?

c) If the response to part (a) is yes, what is the current estimated cost associated with replacing any issues that could be redeemed prior to their maturity date?

d) If the response to part (a) is yes, has EGD done any analysis on the impact on its total debt costs or refinancing some of the debt issues before their maturity date? If yes, please provide a copy of the analysis and any recommendations.

RESPONSE

a) Yes. The public term debt instruments have a Canada Call Provision allowing EGDI to call the term debt at a face value equal to the benchmark Government of Canada Bond yield corresponding to the remaining term to maturity plus 25% of the original issuance spread.

b) The term debt offerings would be redeemable at a premium over face value calculated using the Canada Call Provision outlined in the response above.

Witnesses: K. Culbert
M. Lister
D. Yaworski

c) Please see the response to VECC Interrogatory #1, filed at Exhibit I, Tab E1, schedule 20.1, part b) for an outline of the estimated new issuance cost using 10-years as the replacement term.

d) Yes, EGDI regularly reviews the replacement of select public term debt instruments. At present, the premium required to be paid under the Canada Call Provision exceeds the current market value for each term debt instrument. EGDI's internal analysis and recommendations are proprietary information.

Witnesses: K. Culbert
M. Lister
D. Yaworski

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

E – Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Exhibit E1, Tab 1, Schedule 1

The evidence indicates that a negative amount of deemed short term debt of approximately $22.1 million is proposed for 2013, despite positive short term debt shown for the previous two years.

a) Please update Table 2 to reflect actual data for 2011.

b) Is the negative short-term debt primarily driven by the proposed increase in the common equity ratio? If the common equity ration were to remain at 36%, what would the capital structure shown in Table 4 for the 2013 test year look like?

RESPONSE

a) Please see response to VECC Interrogatory #3 at Exhibit I, Issue E1, Schedule 20.3.

b) The resulting negative short-term debt is a product of the proposed equity level along with the level of existing long and medium term debt. For the requested update of what Table 4 would look like please see the response to VECC Interrogatory #3 at Exhibit I, Issue E1, Schedule 20.3.

Witnesses: K. Culbert
D. Yaworski

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Ref: Exhibit E3, Tab 1, Schedule 1

If necessary, please update the table of medium term notes to reflect actual data for 2011 and for actual data to the end of June 2012.

RESPONSE

The table of medium term notes reflected in Exhibit E3, Tab 1, Schedule 2 does not require updating as a result of actual activity through June 30, 2012. The table appropriately reflects the rates and values of the Company's outstanding medium term notes and long-term debentures.

Witnesses: K. Culbert
D. Yaworski

VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: Exhibit E1 Tab 2 Schedule 1 Page 5

a) Please provide the Government of Canada bond rates and the company specific spreads used to derive the debt rates shown in paragraph 21.

b) Please update the table in paragraph 21 to reflect the most recent forecasts available for 2012 and 2013.

c) Please show/discuss the influence of the change on equity thickness on the 2013 LT debt rate forecast.

RESPONSE

a) Please see the table below:

	2011	2012	2013
Forecasted 10-Year Government of Canada Bond Rate	3.30%	3.80%	4.90%
Forecasted 10-Year New Issuance Spread for EGDI	1.05%	1.00%	1.00%
Forecasted Long Term Debt Rate	4.35%	4.80%	5.90%

b) Please see the table below:

	2012	2013
Forecasted 10-Year Government of Canada Bond Rate	2.40%	3.00%
Forecasted 10-Year New Issuance Spread for EGDI	1.50%	1.50%
Forecasted Long Term Debt Rate	3.90%	4.50%

Witness: D. Yaworski

c) It is Enbridge's position that the deemed common equity component should increase from 36% to 42%. The increased deemed equity level will be viewed positively by the rating agencies and Canadian debt capital market participants. Directionally, an increase could result in a modest reduction to Enbridge's long term debt costs versus the current 2013 long term debt cost forecast.

VECC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: Exhibit E1 Tab 2 Schedule 1
Exhibit E1 Tab 1 Schedule 1

a) Please explain in reference to new Preference Shares how the rate is determined, including the difference between fixed rate and rate reset and the differences between PF1, PF2 and PF3.

b) What is the rating(s) for EGD/EI Preference Shares?

c) Please update the forecasts for 2012 and 2013.

RESPONSE

a) The Canadian preferred share market is largely comprised of two investment alternatives: a perpetual, fixed rate preferred share and a perpetual, rate re-set preferred share. A perpetual fixed rate preferred share is typically issued with a fixed dividend rate through to perpetuity or when the fixed rate preferred share is redeemed by the issuing company. A perpetual, rate re-set preferred share has a fixed dividend rate for the initial term (typically, 5 to 7 years); and the dividend rate re-sets at the end of the initial term (assuming that the issuing company has not redeemed the shares). The dividend rate re-set typically provides the option to re-set the dividend rate at either a fixed or floating rate for the following 5 years. The fixed rate is established using a pre-determined spread over the prevailing 5-year government of Canada bond yield. The floating rate is established using a pre-determined spread over the quarterly re-setting Canadian Deposit Offer Rate (CDOR).

Witnesses: K. Culbert
M. Lister
D. Yaworski

General capital market conditions, investor preference and credit ratings will guide the board price setting for either perpetual fixed rate or perpetual rate re-set preferred shares. Since the dividend rate on perpetual rate re-set preferred shares can be updated to reflect prevailing interest rates, perpetual rate re-set preferred shares are typically offered at dividend yield lower than perpetual fixed rate preferred shares.

P1, P2 and P3 is Standard and Poor's rating convention used to assigned the relative riskiness of a preferred share issued by a company. P1 represents the lowest risk rating with increasing risk through to P3.

b) The following table describes EGD's preference share ratings:

	DBRS	S&P	Moody's
Enbridge Inc.	Pfd-2 (low)	P-2	Baa3
EGDI	Pfd-2 (low)	P-2	N/A

c) Please refer to the response to VECC Interrogatory #1, part 6, at Exhibit I, Tab E1, Schedule 20.1, part b).

Witnesses: K. Culbert
M. Lister
D. Yaworski

VECC INTERROGATORY #3

INTERROGATORY

E- Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: Exhibit E1 Tab 1 Schedule 1

a) Please update Table 2 to reflect actual data for 2011.

b) Provide a version of Table 4 that assumes no change in Equity Thickness.

RESPONSE

a) The following table has been updated to reflect the 2011 Actual/Historical cost of capital. The common equity cost rate utilized is the 2011 Board Approved ROE of 7.94%, plus the 100 basis points (1%) allowed before earnings sharing is triggered, as per the terms of the Company's 2008 through 2012 incentive regulation agreement. This information is also reflected in the updated exhibits at Exhibit E5, Tab 1, Schedule 1, and Exhibit F5, Tab 1, Schedule 1.

Cost of Capital Summary

Line		2011 Historical				
No.		Principal	Component	Cost Rate	Return	Return
		($millions)	%	%	%	($millions)
1.	Long-term debt	2,319.6	58.62%	6.02%	3.53%	139.6
2.	Short-term debt	112.9	2.85%	1.61%	0.05%	1.8
3.	Preferred shares	100.0	2.53%	2.40%	0.06%	2.4
4.	Common equity	1,424.5	36.00%	8.94%	3.22%	127.4
5.	Total	3,957.0	100.00%		6.85%	271.2

Witnesses: K. Culbert
M. Lister
D. Yaworski

b) The following update of Table 4 takes into account the updated results of Impact Statement Number 1 (Exhibit M1, Tab 1, Schedule 5), but assumes common equity thickness remains at 36%, and includes the capital structure impacts for CIS. Please note that the table below assumes the change in the equity ratio (from 42%) is accounted for with short term debt. If the Board did not approve the Company's request for a 42% equity ratio, EGD would investigate financing alternatives, which may include use of long term debt which is different from that presented in the table below.

Cost of Capital Summary (Weighted)

Line No.		2013 Test Year Including CIS Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	2,357.9	56.49%	5.89%	3.33%	138.9
2.	Short-term debt	213.5	5.11%	3.70%	0.19%	7.9
3.	Preferred shares	100.0	2.40%	4.16%	0.10%	4.2
4.	Common equity	1,502.7	36.00%	9.02%	3.25%	135.5
5.	Total	4,174.1	100.00%		6.87%	286.5

Witnesses: K. Culbert
M. Lister
D. Yaworski

VECC INTERROGATORY #4

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: Exhibit E3 Tab 1 Schedule 1

a) Please update the MTN Table for 2011 actuals and 2012 YTD.

b) Provide a Copy of the latest Shelf Prospectus for MTN.

RESPONSE

a) The table of medium term notes reflected in Exhibit E3, Tab 1, Schedule 2 does not require updating as a result of actual activity through June 30, 2012. The table appropriately reflects the rates and values of the Company's outstanding medium term notes and long-term debentures.

b) The latest Shelf Prospectus for MTN is attached.

Witnesses: K. Culbert
M. Lister
D. Yaworksi

Base Shelf Prospectus

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this short form prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities offered hereby have not been and will not be registered under the United States Securities Act of 1933, as amended, and, subject to certain exceptions, may not be offered or sold in the United States of America. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada*. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Enbridge Gas Distribution Inc. at 500 Consumers Road, Toronto, Ontario M2J 1P8 (telephone (416) 495-5922) and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

NEW ISSUE **November 16, 2010**

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION INC.
$800,000,000
MEDIUM TERM NOTES
(UNSECURED)

Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Corporation") may from time to time issue medium term notes (the "Notes") due not less than one year from the date of issue at prices and on terms determined at the time of issue, in an aggregate principal amount of up to $800 million (or the equivalent in foreign currencies) during the twenty-five month period that this short form prospectus ("Prospectus"), including any amendments hereto, remains valid. This offering is a continuation of the Corporation's medium term note program, which was last renewed on May 28, 2008. As of the date of this Prospectus, a total of $2.18 billion principal amount of Notes have been issued and are outstanding. The up to $800 million principal amount of Notes offered hereunder is in addition to such previously issued Notes. The Notes will be issued under a trust indenture and will be direct, unsecured obligations of the Corporation ranking equally and *pari passu* except as to redemption and/or sinking fund provisions, with all other unsecured and unsubordinated indebtedness of the Corporation.

The specific variable terms of any offering of Notes, including the aggregate principal amount offered, price to the public (at par, discount or a premium), currency, date(s) of issue, delivery and maturity, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof) and interest payment date(s), redemption provisions (if redeemable), proceeds to the Corporation, the agents' commission and the name of the registrar and paying agent, will be established at the time of the offering and sale of the Notes and set forth in a pricing supplement (a "Pricing Supplement") or other prospectus supplement which will accompany this Prospectus and any amendment hereto. The Corporation may set forth in a Pricing Supplement or other prospectus supplement specific variable terms of the Notes which are not within the options and parameters set forth in this Prospectus. Notes will be interest-bearing.

There is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "Risk Factors".

In the opinion of counsel to the Corporation, the Notes offered hereby, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) for certain investors as referred to under the heading "Eligibility for Investment".

RATES ON APPLICATION

The Notes will be offered severally by RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., Scotia Capital Inc. and TD Securities Inc. or other investment dealers selected from time to time by the Corporation, acting as agents of the Corporation or underwriters retained by the Corporation (individually, an "Agent" and collectively, the "Agents") in Canada, subject to confirmation by the Corporation pursuant to a selling agency agreement referred to under the heading "Plan of Distribution". The Corporation will pay to each Agent through whom any Note is sold a commission, in an amount to be determined from time to time by mutual agreement, but which will not exceed 0.75% of the principal amount of any Note, unless the Corporation and the Agent otherwise agree. The Notes may also be purchased from time to time by any of the Agents as principal, at such prices and with such commissions as may be agreed between the Corporation and any such Agents, for resale to the public at prices to be negotiated with each purchaser, which prices may vary during the distribution period and as between purchasers. Each Agent's compensation will be increased or decreased by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the aggregate price paid by the Agent, acting as principal, to the Corporation. In connection with any offering of Notes, the Agents may over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. See “Plan of Distribution”. The Corporation may also offer the Notes directly to purchasers, pursuant to applicable statutory exemptions or discretionary exemptions, in which case no commissions will be paid to the Agents.

Under applicable securities legislation in Canada, the Corporation may be considered to be a connected issuer of each of the Agents, as each is a directly or indirectly wholly-owned or majority owned subsidiary of a Canadian chartered bank or financial institution which has extended credit facilities to the Corporation or one or more related issuers of the Corporation. See “Plan of Distribution”.

The offering of Notes is subject to approval of certain legal matters on behalf of the Corporation by McCarthy Tétrault LLP and on behalf of the Agents by Fraser Milner Casgrain LLP**.**

The head and registered office of the Corporation is located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

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DOCUMENTS INCORPORATED BY REFERENCE

The following documents, filed with the securities commission or similar authority in each of the provinces of Canada, are specifically incorporated by reference in, and form an integral part of, this Prospectus provided that such documents are not incorporated by reference to the extent that their contents are modified or superseded by a statement contained in this Prospectus or in any other subsequently filed document that is also incorporated by reference in this Prospectus:

(a) Consolidated comparative financial statements of the Corporation for the year ended December 31, 2009 and the auditors' report thereon;

(b) Management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2009;

(c) Consolidated comparative interim unaudited financial statements of the Corporation for the three and nine month periods ended September 30, 2010;

(d) Management's discussion and analysis of financial condition and results of operations for the three and nine month periods ended September 30, 2010; and

(e) Annual Information Form of the Corporation dated February 18, 2010 (the "AIF").

Any documents of the type referred to above, including any interim financial statements and related management's discussion and analysis, any material change reports (except confidential material change reports), any business acquisition reports and any exhibits to interim unaudited financial statements which contain updated earnings coverage calculations filed by the Corporation with the various securities commissions or similar authorities in Canada after the date of this Prospectus and prior to the termination of this offering shall be deemed to be incorporated by reference into this Prospectus.

Upon a new annual information form and the related annual financial statements and management's discussion and analysis being filed by the Corporation with and, where required, accepted by the applicable securities regulatory authorities during the term of this Prospectus, the previous annual information form, the previous annual financial statements, all interim financial statements and accompanying management's discussion and analysis, material change reports and business acquisition reports filed by the Corporation prior to the commencement of the financial year of the Corporation in respect of which the new annual information form is filed shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder. Upon interim financial statements and the accompanying management's discussion and analysis being filed by the Corporation with the applicable securities regulatory authorities during the term of this Prospectus, all interim financial statements and the accompanying management's discussion and analysis filed prior to the new interim

financial statements shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder.

Any statement contained in this Prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded, for purposes of this Prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of such a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute part of this Prospectus.

A Pricing Supplement or other prospectus supplement containing the specific terms of an offering of Notes will be delivered to purchasers of such Notes together with this Prospectus and will be deemed to be incorporated by reference into this Prospectus as of the date of such supplement solely for the purposes of the offering of the Notes offered thereunder.

Updated earnings coverage ratios will be filed quarterly with the applicable securities regulatory authorities, either as exhibits to the Corporation's unaudited interim and audited annual financial statements or as prospectus supplements and will be deemed to be incorporated by reference into this Prospectus for the purposes of the offering of the Notes.

FORWARD LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Prospectus, including documents incorporated by reference into this Prospectus, to provide readers with information about the Corporation and its subsidiaries, including management's assessment of the Corporation's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this Prospectus include, but are not limited to, statements with respect to expected capital expenditures.

Although the Corporation believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Corporation's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Corporation's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Corporation operates, may impact levels of demand for the Corporation's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

The Corporation's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates and commodity prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this Prospectus and in documents incorporated by reference into this Prospectus. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Corporation's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Corporation assumes no obligation to publicly update or revise any forward-looking statements made in this Prospectus or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are expressly qualified in their entirety by these cautionary statements.

THE CORPORATION

Enbridge Gas Distribution is an indirect wholly-owned subsidiary of Enbridge Inc. ("Enbridge"). Enbridge Energy Distribution Inc. ("EEDI"), itself an indirect wholly owned subsidiary of Enbridge, owns all of the issued and outstanding common shares of Enbridge Gas Distribution.

Enbridge Gas Distribution is a rate regulated natural gas distribution utility serving approximately 1.9 million residential, commercial and industrial customers. There are four principal interrelated aspects of the natural gas distribution business in which the Corporation is directly involved: distribution service, gas supply, transportation and storage.

The main areas in which the Corporation's customers are located are central and eastern Ontario, including Toronto and the surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, Enbridge Gas Distribution serves Massena, Ogdensburg, Potsdam and surrounding areas in northern New York State through St. Lawrence Gas Company, Inc. ("St. Lawrence"), a wholly owned subsidiary of the Corporation.

The utility business is conducted under statutes and municipal by-laws, which grant the right to operate in the areas served. Various aspects of the utility operations in Ontario are regulated by the Ontario Energy Board (the "OEB") with similar regulation applying to St. Lawrence by way of the New York State Public Service Commission.

Enbridge Gas Distribution was incorporated in 1848 by *Special Act*, II Victoria Cap. XIV, of the Province of Canada. By letters patent dated September 30, 1954, Enbridge Gas Distribution was continued under the *Corporations Act*, 1953 (Ontario) and is now subject to the *Business Corporations Act* (Ontario).

Enbridge Gas Distribution's registered office and principal place of business is located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

USE OF PROCEEDS

The aggregate principal amount of the Notes offered under this Prospectus shall not exceed $800 million in Canadian currency or equivalent thereof in foreign currencies. The net proceeds to be received by the Corporation from the sale from time to time of Notes under this Prospectus will be the issue price thereof less any commissions and expenses paid in connection therewith. The net proceeds cannot be estimated as at the date hereof since the amount thereof will depend on the terms and conditions of the Notes and the extent to which Notes are issued under this Prospectus. The net proceeds from the sale of the Notes will be added to the general funds of the Corporation to be used for general corporate purposes, which may include reducing outstanding indebtedness and financing capital expenditures, investments and working capital requirements of the Corporation. The Corporation may, from time to time, issue debt instruments and incur additional indebtedness otherwise than through the issue of Notes pursuant to this Prospectus.

The net proceeds to be received by the Corporation from the sale of Notes from time to time under this Prospectus are not expected to be applied to fund any specific project. The Corporation's overall corporate strategy and major initiatives supporting its strategy are summarized in the Corporation's management's discussion and analysis for the year ended December 31, 2009, as modified or superseded by information contained in the Corporation's management's discussion and analysis for the three and nine month periods ended September 30, 2010, and subsequent periods, incorporated herein by reference.

PLAN OF DISTRIBUTION

Pursuant to the terms of a selling agency agreement (the "Agency Agreement") dated November 16, 2010 between the Corporation and the Agents, the Agents are or will be authorized, as agents of the Corporation for this purpose only, to solicit offers to purchase Notes, directly or through other Canadian investment dealers. The Corporation will pay each Agent through whom any Note is sold a commission as set forth in Schedule "A" of the Agency Agreement, unless the Corporation and the Agent otherwise agree.

The Agency Agreement also provides that Notes may be purchased from time to time by any of the Agents as underwriter or principal, at a price to be agreed between the Corporation and the Agent, for resale to other dealers or purchasers at prices to be negotiated with each such investment dealer or purchaser. Such resale prices may vary during the distribution period and as between purchasers. Commissions may be paid in connection with such purchases in such amounts as may be agreed between the Corporation and any such Agent. The Agent's compensation will be increased or decreased by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the aggregate price paid by the Agent, acting as underwriter or principal, to the Corporation.

The Corporation may also offer the Notes directly to purchasers, pursuant to applicable statutory exemptions or discretionary exemptions, at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commission will be paid to the Agents.

The Notes have not been and will not be registered under the *United States Securities Act* of 1933, as amended (the "Securities Act"), and may not be offered, sold or delivered in the United States or to, or for the account or benefit of, U.S. persons (as defined in Regulation S under the Securities Act) except in transactions exempt from the registration requirements of the Securities Act pursuant to Rule 144A thereunder. The Agents have severally agreed that they will not offer or sell the Notes in the United States, except in such an exempt transaction. In addition, until 40 days after the commencement of the offering of any Notes, an offer or sale of any such Notes within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with an applicable exemption from the registration requirements of the Securities Act.

In connection with any offering of Notes, the Agents may over allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Agents may purchase and sell Notes from time to time in the secondary market but are not obligated to do so. There can be no assurance that there will be a secondary market for the Notes. The offering price and other selling terms for such sales in the secondary market may, from time to time, be varied by the Agents.

The Corporation and, if applicable, the Agents, reserve the right to reject any offer to purchase Notes in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of Notes hereunder without notice.

Under applicable securities legislation in Canada, the Corporation may be considered to be a connected issuer of each of the Agents as each of the Agents other than Merrill Lynch Canada Inc. and Desjardins Securities Inc. is a directly or indirectly wholly-owned or majority owned subsidiary of a Canadian chartered bank or financial institution (collectively, the "EGDI Banks") which has extended a credit facility to the Corporation and each of the Agents is a directly or indirectly wholly-owned or majority owned subsidiary of a Canadian chartered bank or financial institution (collectively, the "Banks") which has extended credit facilities to one or more related issuers of the Corporation. The Corporation's credit facility with the EGDI Banks consists of a $700 million syndicated 364-day revolving facility. All such credit facilities are unsecured and each borrower thereunder is and has been since the establishment thereof, in compliance with the terms of the agreements governing them. The financial position of each of the Corporation and each other borrower under such credit facilities has not adversely changed in any material manner since the respective credit facility was put in place. The principal purpose of these credit facilities is to finance the near term growth capital expenditures and to support repayment obligations under commercial paper programs. The Corporation may incur additional indebtedness to the EGDI Banks under its credit facility and net proceeds received pursuant to offerings under this Prospectus may be used, directly or indirectly, to reduce that indebtedness. None of the Banks were involved in the decision to offer the Notes and none will be involved in the determination of the terms of the distribution of the Notes. As a consequence of the sale of the Notes through any of the Agents from time to time under this Prospectus, the Corporation will pay a commission to each Agent through which a Note is sold.

DESCRIPTION OF NOTES

The following description of the Notes is a summary of their material attributes and characteristics which does not purport to be complete. Certain of the capitalized terms used but not defined in this section have the meanings set out in Schedule A hereto. The terms and conditions set forth in this section will apply to each Note unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement. For further particulars of the terms of the Notes, reference should be made to the Indenture (as defined below).

General

The Notes will be issued under a trust indenture dated October 9, 1996, as amended and supplemented from time to time (the "Indenture"), between the Corporation and CIBC Mellon Trust Company, as trustee (the "Trustee").

The Notes will be direct unsecured obligations of the Corporation and will not be secured by any mortgage, hypothec, pledge or other charge, except in circumstances as required by the Indenture. The Notes will rank equally and *pari passu*, except generally as to redemption and/or sinking fund provisions, with all other debentures, notes and other unsecured and unsubordinated indebtedness incurred by the Corporation, including its outstanding medium term notes and debentures, and will rank junior to First Mortgage Bonds issued under a trust deed and secured by a fixed and floating charge on the assets of the Corporation. There are currently no First Mortgage Bonds outstanding. The debentures of the Corporation issued under various trust indentures and the outstanding medium term notes of the Corporation have the benefit of a negative pledge subject to exceptions including the issue of First Mortgage Bonds.

A financial institution or institutions as appointed by the Corporation and designated in the pricing supplement or other prospectus supplement will act as the issuing agent, registrar and transfer agent and paying agent of the Notes.

The specific terms of any offering of Notes, including the aggregate principal amount offered, price to the public (at par, discount or a premium), currency, dates of issue, delivery and maturity, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), interest payment date(s), redemption provisions, if any, proceeds to the Corporation, the Agents' commission and the name of the registrar and paying agent, will be established at the time of the offering and sale of the Notes and set forth in a Pricing Supplement or other prospectus supplement which will accompany this Prospectus and any amendment hereto. The Corporation may set forth in a Pricing Supplement or other prospectus supplement specific variable terms of the Notes which are not within the options and parameters set forth in this Prospectus.

Term and Denomination

The Notes will have maturities of not less than one year from the date of issue, will bear interest at a fixed or floating rate and will be issuable in fully registered form in denominations of $1,000 and integral multiples thereof with the minimum subscription being $5,000, or in each case the approximate equivalent amount thereof in a foreign currency.

Fixed and Floating Rate Notes

Notes may be issued as a fixed rate Note (a "Fixed Rate Note") or a floating rate Note (a "Floating Rate Note") or as a Note that is a Fixed Rate Note for a portion of its term and a Floating Rate Note for a portion of its term, all as specified in the applicable Pricing Supplement or other prospectus supplement.

Notes will bear interest from their date of issue or from the last interest payment date to which interest has been paid, whichever is later, provided that, in respect of the first interest payment after the issuance thereof, each Note will bear interest from the later of the date of such Note and the last interest payment date preceding the issuance of such Note. Interest on Fixed Rate Notes will be payable quarterly, semi-annually, annually or as otherwise specified in the applicable Pricing Supplement or other prospectus supplement, on the interest payment dates specified in the Notes and in the applicable Pricing Supplement or other prospectus supplement and at maturity. Interest on Floating Rate Notes will be payable on the interest reset dates specified in the Note and in the applicable Pricing Supplement or other prospectus supplement and at maturity.

Unless otherwise provided for in the applicable Pricing Supplement or other prospectus supplement, any interest on Notes will be determined on an actual/actual day count basis pursuant to which the actual number of days in the applicable interest period is divided by 365 (or, if any portion of the interest period falls in a leap year, the sum of (i) the actual number of days in that portion of the interest period falling within a leap year divided by 366 and (ii) the actual number of days in that portion of the interest period falling within a non-leap year divided by 365).

Global Notes

Unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement, all Notes denominated in Canadian or United States dollars will be represented in the form of fully registered global Notes (each, a "Global Note") held by, or on behalf of CDS Clearing and Depository Services Inc. or a successor (collectively, the "Depository"), as custodian of the Global Notes (for its participants as defined below) and registered in the name of the Depository or its nominee. Except as described below, no purchaser of a Note will be entitled to a certificate or other instrument from the Corporation or the Depository evidencing the purchaser's ownership of the Note. Instead, the Notes will be represented only in book-entry form. Beneficial interests in the Global Notes, constituting ownership of the Notes, will be represented through book-entry accounts of institutions (including the Agents) acting on behalf of beneficial owners, as direct and indirect participants of the Depository ("participants"). Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Agent or Agents from whom the Note is purchased in accordance with the practices and procedures of the selling Agent or Agents. The practices of the Agents may vary but generally customer confirmations are issued promptly after execution of a customer order. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

Currently, the Depository only allows depository eligibility for securities denominated in Canadian or United States dollars. Any Notes denominated in a currency other than Canadian or United States dollars will be represented by Notes in definitive form ("Definitive Notes") until such time as the Depository allows depository eligibility for issues of securities denominated in such currencies.

If the Depository notifies the Corporation that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and the Corporation and the Trustee are unable to locate a qualified successor, or if an event of default has occurred and is continuing with respect to the Notes, or if the Corporation elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes. Beneficial owners of Notes represented by Global Notes may also receive Definitive Notes if the Trustee gives notice pursuant to the Indenture that an event of default has occurred and is continuing with respect to the Notes. In addition, if provided in the applicable Pricing Supplement or other prospectus supplement, Notes may be issued in the form of Definitive Notes.

Payment of Interest and Principal

The Depository or its nominee, as the registered owner of a Global Note, will be considered the sole owner of such Note for the purposes of receiving payments of interest and principal on the Note and for all other purposes under the Indenture and the Note.

The Corporation understands that the Depository or its nominee, upon receipt of any payment of interest or principal in respect of a Global Note, will credit participants' accounts on the date interest or principal is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or its nominee. The Corporation also understands that payments of interest and principal by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices. The responsibility and liability of the Corporation in respect of Notes represented by a Global Note is limited to making payment of any interest and principal due on such Global Note to the Depository or its nominee in the currency and in the manner described in the Global Note.

Transfer of Notes

Transfers of beneficial ownership of Notes represented by Global Notes will be effected through records maintained by the Depository or its nominee (with respect to interests of participants) and on the records of participants (with respect to interests of persons other than participants). Beneficial owners who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interest in Global Notes, may do so only through participants in the Depository's book entry system.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest in a Note represented by a Global Note (other than through a participant) may be limited due to the lack of a physical certificate.

The registered holder of a Definitive Note may transfer or exchange such Note upon payment of taxes incidental thereto, if any, by executing and delivering a form of transfer together with the Definitive Note to the applicable registrar and paying agent at its principal office in any of the cities of Vancouver, Calgary, Toronto, Montreal and Halifax whereupon a new Definitive Note will be issued in authorized denominations in the same aggregate principal amount as the Definitive Note so transferred, registered in the names of the transferees. No transfer of a Note will be registered during the ten business days (a business day for this purpose being a business day in the City of Toronto) immediately preceding any date fixed for payment of interest on such Note or five business days prior to the date of selection by the Trustee of any Notes to be redeemed.

Redemption and Purchase of Notes

Notes will not be redeemable by the Corporation or repayable at the option of the holder prior to maturity, unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement. The Corporation may at any time when not in default under the Indenture purchase Notes in the market (which shall include purchases from or through an investment dealer or a firm holding membership on a recognized stock exchange), or by tender, or by private contract, in accordance with the Indenture. Notes redeemed or purchased by the Corporation will be cancelled and may not be reissued.

Negative Covenants

In addition to certain other covenants in the Indenture, the Corporation covenants substantially to the effect that so long as any of the Notes are outstanding, it will not:

(a) except from time to time to secure First Mortgage Bonds, mortgage, pledge or charge or otherwise encumber any of its assets to secure any obligations unless at the same time it shall, in the opinion of counsel to the Corporation, secure equally and rateably with such obligations all of the Notes then outstanding by the same instrument or by other instrument in form and substance satisfactory to such counsel; provided that this shall not apply to (i) Permitted Prior Charges, (ii) Purchase Money Obligations, (iii) security given in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, to secure any obligation repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such obligation is incurred provided such security is not given on fixed assets, or (iv) permitted encumbrances (as defined in the Indenture);

(b) permit any Restricted Subsidiary to create, incur or guarantee any indebtedness, except indebtedness to or of the Corporation or to a trustee in support of a guarantee of indebtedness of the Corporation; provided that this shall not apply to (i) Permitted Prior Charges, (ii) Purchase Money Obligations, or (iii) indebtedness incurred in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such indebtedness is incurred, provided such security is not given on fixed assets;

(c) dispose of any indebtedness of a Restricted Subsidiary held by or for the Corporation;

(d) permit any Restricted Subsidiary to issue any shares if, as a result of such issue, such Restricted Subsidiary ceases to qualify as such; or

(e) create or issue any additional notes unless the Consolidated Net Earnings of the Corporation for any period of 12 consecutive calendar months of the 23 calendar months next preceding the date of application to the Trustee for certification of such additional notes, which shall have been selected by the Corporation, shall have been at least two times the annual interest requirements in respect of all Funded Obligations of the Corporation to be outstanding after the issue of such additional notes and after any retirements of Funded Obligations to be made out of the proceeds thereof or retirement whereof has been otherwise provided for and in respect of which proof has been afforded to the Trustee satisfactory to it that adequate provision has been made assuring that such Funded Obligations will be retired within 45 days after the issue of such additional notes; provided that the provisions of this covenant (e) shall not apply to the creation and issue of additional notes for the purpose of refunding any notes previously issued provided that (except in the case of refunding all of the notes) the aggregate principal amount of the additional notes does not exceed the aggregate principal amount of the notes to be refunded.

Modification

The rights of the holders of notes under the Indenture may be modified. For that purpose, among others, the Indenture contains provisions making binding upon all holders of notes, including all other medium term notes of the Corporation issued prior to the creation of the Trust Indenture, resolutions passed at meetings of such noteholders by the favourable votes of the holders of not less than 66 ⅔% of the principal amount of such notes voted on the resolution or instruments in writing signed by the holders of not less than 66 ⅔% of the principal amount of all such outstanding notes. In certain cases, modification will require separate assent by the holders of the required percentages of notes of each series or tranche outstanding under the Indenture or otherwise. Reference is made to the Indenture for detailed provisions relating to voting and meetings of noteholders.

CREDIT RATINGS

The Corporation's senior unsecured indebtedness currently has a rating of "A" by DBRS Limited ("DBRS") and "A-" by Standard & Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("S&P") (DBRS and S&P are each a "Rating Agency"). The rating outlook from DBRS is stable and the rating outlook from S&P is stable. These ratings are subject to change at any time at the sole discretion of the Ratings Agencies. We expect that at the date of issuance of any Notes, such Notes will be assigned the same ratings by these Rating Agencies. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The Rating Agencies' ratings for debt instruments range from a high of AAA to a low of D for DBRS and in the case of S&P, from a high of AAA to a low of D.

According to DBRS' rating system, debt securities rated A are characterized as "satisfactory credit quality" and this rating is the third highest of ten available rating categories. Protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. While a respectable rating, entities in the A category are considered to be more susceptible to adverse economic conditions and have higher cyclical tendencies than higher rated securities. The assignment of a "high" or "low" designation within each rating category indicates relative standing within such category. The absence of a "high" or "low" designation indicates the rating is in the "middle" of the category. The "high", "middle" and "low" grades are not used for the AAA and D categories.

According to the S&P rating system, an obligation rated A- is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Notes are not recommendations to purchase, hold or sell the Notes. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely at any time by a Rating Agency in the future if, in its judgment, circumstances so warrant. The lowering of any rating of the Notes may negatively affect the quoted market price, if any, of the Notes. See "Risk Factors".

EARNINGS COVERAGE RATIOS

The following earnings coverage ratios have been calculated on a consolidated basis for the respective 12 month periods ended December 31, 2009 and September 30, 2010 and are derived from audited financial information, in case of December 31, 2009, and unaudited financial information, in the case of September 30, 2010. The following earnings coverage ratios: (i) do not give effect to the issue of any Notes pursuant to this Prospectus; (ii) do not purport to be indicative of earnings coverage ratios for any future periods; and (iii) have been calculated based on Canadian GAAP. The following earnings coverage ratios give effect to the issuance of all of the Corporation's currently outstanding debt securities and assume repayment thereof as of the respective stated maturities of such debt securities.

	December 31, 2009	**September 30, 2010**
Earnings coverage on long term debt	2.5 times	2.3 times

ELIGIBILITY FOR INVESTMENT

In the opinion of McCarthy Tétrault LLP, counsel to the Corporation, subject to the provisions of any particular registered plan or account, the Notes offered hereby, if issued on the date hereof, would be qualified investments under the Income Tax Act (Canada) (the "Tax Act") for trusts governed by registered retirement savings plans, registered retirement income funds, registered disability savings plans, registered education savings plans, deferred profit sharing plans (other than trusts governed by deferred profit sharing plans to which contributions are made by the Corporation or persons or partnerships with which the Corporation does not deal at arm's length for purposes of the Tax Act and tax-free savings accounts ("TFSAs"). Notwithstanding that the Notes may be a qualified investment for a trust governed by a TFSA, the holder of a TFSA that governs a trust which holds Notes will be subject to a penalty tax if the holder does not deal at arm's length with the Corporation for the purposes of the Tax Act or if the holder has a significant interest (within the meaning of the Tax Act) in the Corporation or a corporation, partnership or trust with which the Corporation does not deal at arm's length for the purposes of the Tax Act.

The Minister of Finance (Canada) has recently released proposed amendments to the Tax Act (the "Proposed TFSA Amendments") which will, if enacted, subject certain income of a TFSA to tax. The Proposed TFSA Amendments will subject any transfer of property occurring after October 16, 2009 (other than a transfer that is a distribution or a contribution) occurring between a holder's TFSA and the holder or a person who does not deal at arm's length, within the meaning of the Tax Act, with a holder (including, for example, another exempt plan of the holder) to a tax equal to 100% of the increase in the total fair market value of the property held in connection with the holder's TFSA that is attributable to the transfer. The Proposed TFSA Amendments will also subject any income (including capital gains) earned after October 16, 2009 that is reasonably attributed to a "prohibited investment" or a "deliberate over-contribution", each within the meaning of the Tax Act and the Proposed TFSA Amendments, to tax equal to 100% of the income or capital gain. No assurance can be given that the Proposed TFSA Amendments will be enacted in their current form, or at all. **Prospective purchasers who intend to hold Notes in their TFSAs should consult their own tax advisors regarding their particular circumstances.**

LEGAL MATTERS

Certain legal matters in connection with the issuance of the Notes will be passed upon on behalf of the Corporation by McCarthy Tétrault LLP and on behalf of the Agents by Fraser Milner Casgrain LLP. Each of the partners and associates of McCarthy Tétrault LLP as a group, and the partners and associates of Fraser Milner Casgrain LLP as a group, beneficially own, directly or indirectly, not more than 1% of the outstanding securities of each class of the Corporation.

RISK FACTORS

In addition to the risk factors set forth below, additional risk factors are discussed in the AIF and in the Corporation's management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2009, which risk factors are incorporated herein by reference. Prospective purchasers of Notes should consider carefully the risk factors set forth below as well as other information contained in and incorporated by reference in this Prospectus, and in the applicable prospectus supplement before purchasing the Notes offered hereby.

Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Notes are not a recommendation to purchase, hold or sell the Notes, because ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time or that these ratings will not be revised or withdrawn entirely in the future by the relevant rating agency. Real or anticipated changes in credit ratings on the Notes may affect the market value of the Notes. In addition, real or anticipated changes in credit ratings can affect the cost at which the Corporation can access the debt market.

Lack of Public Market for the Notes

This Prospectus qualifies new issues of Notes for which there is no existing trading market. The Corporation does not intend to list the Notes on any securities exchange or to arrange for any quotation system to quote the Notes. There can be no assurance as to the liquidity of any trading market for the Notes or that a trading market for any of the Notes will develop. Even if a trading market develops for the Notes, those Notes could trade at prices that may be higher or lower than their initial offering prices. The market price for the Notes may be affected by prevailing interest rates, the Corporation's results of operations and financial position, the ratings assigned to the Notes or the Corporation, changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Corporation.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus, the accompanying Pricing Supplement or other prospectus supplement relating to the securities purchased by a purchaser and any amendment thereto. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus, the accompanying Pricing Supplement or other prospectus supplement relating to the securities purchased by a purchaser and any amendment thereto contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province of residence. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province of residence for the particulars of these rights or consult with a legal adviser.

CERTIFICATE OF ENBRIDGE GAS DISTRIBUTION INC.

Dated: November 16, 2010

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

Janet A. Holder *"Janet A Holder"*	Narinder K. Kishinchandani *"Narinder K. Kishinchandani"*
President (as Chief Executive Officer)	Vice President, Finance (as Chief Financial Officer)

On behalf of the Board of Directors

J. Lorne Braithwaite *"J. Lorne Braithwaite"*	David A Leslie *"David A Leslie"*
Director	Director

CERTIFICATE OF THE AGENTS

Dated: November 16, 2010

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

RBC Dominion Securities Inc.

"Tushar Kittur"
Tushar Kittur

BMO Nesbitt Burns Inc.

"Aaron M. Engen"
Aaron M. Engen

CIBC World Markets Inc.

"Sean Gilbert"
Sean Gilbert

Desjardins Securities Inc.

"Ryan Godfrey"
Ryan Godfrey

HSBC Securities (Canada) Inc.

"Rod A. McIssac"
Rod A. McIssac

Merrill Lynch Canada Inc.

"Timothy W. Watson"
Timothy W. Watson

National Bank Financial Inc.

"Iain Watson"
Iain Watson

Scotia Capital Inc.

"Murray W. Neal"
Murray W. Neal

TD Securities Inc.

"Alec W.G. Clark"
Alec W.G. Clark

SCHEDULE A
DEFINITIONS

The following terms which are used above are defined in the Indenture substantially as follows:

"***additional notes***" means all Funded Obligations of the Corporation other than First Mortgage Bonds and the previously issued medium term notes and debentures of the Corporation.

"***Attributable Debt***" means, as to any particular lease under which any person is at the time liable and at any date as of which the amount thereof is to be determined, the lesser of (i) the fair market value of the property (as determined by the directors) subject to such lease, and (ii) the total net amount of rent required to be paid by such person under such lease during the remaining term thereof (including any period for which such lease has been extended), discounted from the respective due dates thereof to such date at a rate of interest per annum equal to the weighted average interest rate of all unsecured and unsubordinated indebtedness of the Corporation. The net amount of rent required to be paid under any such lease for any such period shall be the aggregate amount of the rent payable by the lessee with respect to such period after excluding amounts required to be paid on account of maintenance and repairs, insurance, taxes, assessment, water rates and similar charges. In the case of any lease which is terminable by the lessee upon payment of a penalty, such net amount shall also include the amount of such penalty, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated.

"***Consolidated Net Earnings***" for any specified period of 12 months means the net earnings of the Corporation on a consolidated basis for such period (excluding gains or losses on the disposal of investments or fixed assets in each case in excess of $50,000 in the aggregate and other non recurring items in excess of $50,000 in the aggregate) before deductions for income taxes, interest on Funded Obligations of the Corporation, dividends on preferred shares of the Corporation which have been deducted to calculate net earnings, amortization of debt premium, discount and expense and the cost, whether or not amortized, of conversion of facilities and appliances of the Corporation and its customers to the use of natural gas, all as determined in accordance with generally accepted accounting principles and reported on by the Corporation's auditors without, in their opinion, material adverse qualification; provided that if, within or after the period for which Consolidated Net Earnings is being determined but at or prior to the issuance of the additional notes in respect of which such determination is being made, the Corporation or any company, a portion of the net earnings (losses) of which are included in determining Consolidated Net Earnings acquires (a) any assets, or (b) an interest in any other company which would thereafter permit the inclusion in Consolidated Net Earnings of the Corporation's equity in the net earnings (losses) of such other company, then Consolidated Net Earnings may be determined as if such assets or interest had been acquired prior to and owned throughout such period if net earnings (losses) from such assets or interest can be determined or estimated for such period in accordance with generally accepted accounting principles.

"***Consolidated Net Tangible Assets***" means, on any date, the aggregate amount of assets after deducting therefrom (i) all current liabilities, and (ii) all goodwill, trade names, trade marks, patents, organization expenses and other like intangibles of the Corporation and its consolidated subsidiaries, all as set forth on the most recent balance sheet of the Corporation and its consolidated subsidiaries and determined in accordance with generally accepted accounting principles.

"***Excluded Sale and Leaseback***" means any Sale and Leaseback in respect of which:

(a) the lease is for a period, including renewal rights, of not in excess of three years, or

(b) an amount equal to the greater of the net proceeds of the sale of the property leased pursuant to such arrangement and the fair market value of such property (as determined by the directors) is applied within 180 days after the sale has been completed to:

  (i) the retirement, otherwise than by payment at maturity or pursuant to any mandatory sinking fund payment or any mandatory prepayment provision, of Funded Obligations of the Corporation or a Restricted Subsidiary, or

  (ii) the purchase of other property having a fair market value (as determined by the directors) at least equal to the fair market value (as so determined) of the property leased in such Sale and Leaseback, or

(c) such Sale and Leaseback is entered into prior to, at the time of, or within 180 days after the acquisition of the property which is subject thereto, or

(d) the only parties are the Corporation and Restricted Subsidiaries.

"***First Mortgage Bonds***" means all first mortgage bonds or other first mortgage obligations of the Corporation, whether heretofore or hereafter issued, secured by a first fixed and specific charge on substantially all the fixed assets of the Corporation (whether or not also secured by floating charge or by any other security) and includes, without limitation, the first mortgage bonds of the Corporation outstanding from time to time under a Deed of Trust and Mortgage dated as of November 1, 1954 (and deeds supplemental thereto) made by the Corporation and The Toronto General Trusts Corporation (succeeded by Montreal Trust Company of Canada), as trustee.

"***Funded Obligations***" means any indebtedness, whether by way of bonds, debentures, debenture stock, notes or otherwise, whether secured or unsecured, the due date of payment of which, including any right of extension or renewal, is 18 months or more after the date of issue or incurring thereof but does not include Purchase Money Obligations or Permitted Prior Charges.

"***Permitted Prior Charges***" means Sale and Leasebacks and security for obligations, except First Mortgage Bonds, of the Corporation or any of its Restricted Subsidiaries, provided that the aggregate amount of the Attributable Debt of the Corporation and its Restricted Subsidiaries of all Sale and Leasebacks, excepting Excluded Sale and Leasebacks, and all obligations of the Corporation and its Restricted Subsidiaries so secured does not exceed the greater of 5% of Consolidated Net Tangible Assets of the Corporation and 10% of Shareholders' Equity of the Corporation.

"***Purchase Money Obligations***" means any mortgages, hypothecs, charges, vendors' privileges, vendors' liens, or other encumbrances upon property (and the indebtedness represented thereby) given or assumed or arising by operation of law, to provide or secure the whole or any part of the consideration for the acquisition of such property and includes renewals, refundings and extensions not in excess of the principal amount thereof immediately prior to such renewal, refunding or extension.

"***Restricted Subsidiary***" means any corporation, company or organization, more than 50% of the outstanding shares of each class of the capital stock of which having attached to them voting rights under all circumstances are owned by the Corporation and/or one or more Restricted Subsidiary, provided the Corporation shall have, by resolution of its directors, designated such corporation, company or organization as a Restricted Subsidiary and more than 50% of the outstanding shares of each such class of the capital stock thereof are still owned by the Corporation and/or one or more Restricted Subsidiary.

"***Sale and Leaseback***" means any transaction with any bank, insurance company or other lender or investor, or to which any such bank, insurance company, lender or investor is a party, providing for the leasing by the Corporation or a Restricted Subsidiary of any property, real or personal, moveable or immovable, which has been or is to be sold or transferred by the Corporation or such Restricted Subsidiary to such bank, insurance company, lender or investor in contemplation of such leasing.

"***Shareholders' Equity***" means, on any date, the total amount of shareholders' equity of the Corporation and its consolidated subsidiaries including future income tax liabilities, all as set forth in the most recent consolidated balance sheet of the Corporation and its consolidated subsidiaries and determined in accordance with generally accepted accounting principles.

SCHEDULE B
AUDITORS' CONSENT

We have read the short form base shelf prospectus of Enbridge Gas Distribution Inc. (the "Corporation") dated November 16, 2010 relating to the qualification for distribution by the Corporation of up to $800 million Medium Term Notes (unsecured). We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use, through incorporation by reference, in the above-mentioned prospectus of our report to the shareholders of the Corporation on the consolidated statements of financial position of the Corporation as at December 31, 2009 and 2008 and on the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years ended December 31, 2009 and December 31, 2008. Our report is dated February 18, 2010.

(signed) *"PricewaterhouseCoopers LLP"*

Chartered Accountants, Licensed Public Accountants
Toronto, Ontario, Canada
November 16, 2010

CME, CCC, SEC, VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: EGDI Evidence E1, Tab 1, Schedule 1, Tables 1 to 4, Testimony of K. Culbert.

Cost of $100M preference shares

a) Please provide the history of EGDI's preference shares and in particular why the cost has decreased from 5.0% in 2007 to 2.48% in 2011 and is forecast to increase to 4.16% in 2013, when there is no new preferred share financing planned.
b) Please indicate the breakdown of the preferred shares into floating and fixed rate preferred shares.
c) Please provide a before tax cost analysis of EGDI's use of preferred share financing versus the use of straight debt.
d) Please indicate the breakdown of the preferred share financing in terms of their balance sheet allocation, that is, are they treated as debt, equity or preferred shares.
e) Please indicate whether EGDI or Concentric has taken these preferred shares into account in their capital structure recommendation and if so how.

RESPONSE

a) In 2007, the holders of EGDI's preferred shares were within a 5-year fixed dividend rate term at 4.97%. In July 2009, the holders of EGDI's preferred shares elected a floating rate calculation for dividend payments. As a result, the dividend rate is re-set quarterly at 80% of the average Canadian prime lending rate offered by Bank of Montreal and Toronto-Dominion Bank. The following summarizes the Company's forecast for Canadian prime for 2011 through to 2013:

Witnesses: J. Coyne
K. Culbert
J. Liberman
M. Lister
R. Small
D. Yaworski

	2011	2012	2013
Canadian Prime Lending Rate	3.30%	4.10%	5.20%

b) In July 2009, the holders of EGDI's preferred shares elected a floating rate option for dividend payments for the $100 million preferred shares outstanding.

c) Preferred shares are afforded a 50% equity treatment by DBRS and Standard & Poor's. The balanced comparative analysis would involve the comparative costs between issuing $100 million in preferred shares with the combined issuance of $50 million in common equity and $50 million in term debt. Since EDGI does not issue public common equity, an interpolated cost of equity has been developed based on the Company's A- rating. The comparative analysis is outlined below:

Cost of Equity		Cost of Debt	
Company Rating (S&P)	A-		
30-Year GoC Yield [1]	4.00%	10-Year GoC Yield [4]	1.58%
Adjusted Beta [2]	0.61	10-Year Indicative Spread [4]	1.20%
Market Risk Premium [3]	6.00%		
Cost of Equity	7.63%	Cost of Debt (Before Tax)	2.78%
Weighting	50%	Weighting	50%
	3.82%		1.39%

Weighted Average Cost of Capital: 5.21%

[1] Mean-reverted 30-year Government of Canada
[2] Interpolated Adjusted Beta for A- Rated Canadian Utilities based on daily, historical regression versus S&P 500
[3] Assumes a Market Risk Premium of 6.5%; based on the Dividend Discount Model, Sharpe Ratio and AA Bonds
[4] For the week ending July 27, 2012

Witnesses: J. Coyne
K. Culbert
J. Liberman
M. Lister
R. Small
D. Yaworski

Preferred Shares			
	2011	2012	2013
Forecasted Prime Rate	3.30%	4.10%	5.20%
Dividend Rate Adjustment	80%	80%	80%
Dividend Rate	2.64%	3.28%	4.16%

3-Year Average Dividend Rate: 3.36%

On a pre-tax basis, the preferred shares have a 185 bps pricing advantage over the comparative combination of common equity and debt.

d) The preferred shares are treated 100% as preferred shares on the balance sheet.

e) It is Concentric's understanding that the Board does not differentiate between preferred and common equity in its equity thickness determination and that the Company has the flexibility to utilize preferred equity in its capital structure so long as the actual capital structure does not deviate significantly from the applicable deemed capital structure. As such, Concentric has considered common equity and preferred equity to be one and the same for purposes of Concentric's equity thickness recommendation. Note that Exhibit Concentric-02 had not considered preferred equity in arriving at proxy group capital structures. Below, Concentric has recreated the exhibit showing the applicable preferred equity for each company as a component of equity.

Witnesses: J. Coyne
K. Culbert
J. Liberman
M. Lister
R. Small
D. Yaworski

PROXY GROUP CAPITAL STRUCTURES

			Long-Term Debt				Shareholders' Equity					
		Short-Term Debt	Current Portion	Non-Current Portion	Total Debt	%	Preferred Equity	Non-Controlling Interest	Common Equity	Total Equity	%	Total Capital
U.S. NATURAL GAS DISTRIBUTION UTILITIES												
National Fuel Gas Company	NFG	40	150	899	1,089	36.5%	-	-	1,892	1,892	63.5%	2,981
Northwest Natural Gas Company	NWN	181	40	602	823	54.2%	-	-	697	697	45.8%	1,520
Piedmont Natural Gas Company, Inc.	PNY	270	60	675	1,005	49.6%	-	-	1,022	1,022	50.4%	2,027
Questar Corporation	STR	278	25	881	1,184	52.0%	-	-	1,094	1,094	48.0%	2,278
Sempra Energy	SRE	641	137	10,033	10,811	52.0%	-	354	9,630	9,984	48.0%	20,795
Southwest Gas Corporation	SWX	-	221	937	1,158	49.4%	-	(1)	1,188	1,187	50.6%	2,345
Vectren Corporation	VVC	216	138	1,581	1,936	57.1%	-	-	1,452	1,452	42.9%	3,388
						50.1%					49.9%	
CANADIAN UTILITIES												
Canadian Utilities Limited	CU	-	294	3,724	4,018	49.2%	824	343	2,974	4,141	50.8%	8,159
Emera Incorporated	EMA	184	17	3,147	3,348	63.5%	147	224	1,557	1,927	36.5%	5,275
Enbridge Inc.	ENB	430	96	14,566	15,092	62.9%	613	669	7,629	8,911	37.1%	24,003
Fortis Inc.	FTS	242	91	5,824	6,157	57.2%	592	205	3,809	4,606	42.8%	10,763
TransCanada Corporation	TRP	1,865	1,189	18,806	21,860	53.7%	1,224	1,496	16,105	18,825	46.3%	40,685
						57.3%					42.7%	

as of Q3 2011: Source: SNL Financial

Witnesses: J. Coyne
K. Culbert
J. Liberman
M. Lister
R. Small
D. Yaworski

CME, CCC, SEC, VECC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: EGDI Evidence E1, Tab 2, Schedule 1,Testimony of D. Yaworski.

Commercial paper and long term debt cost

a) Please provide an all-in cost analysis of the commercial paper program by including forecast “interest” costs as well as standby and other bank fees.

b) Please indicate whether the typical electricity distributor allowed a 40% common equity ratio by the Board has access to the CP market, and if not please explain why not.

c) Please confirm that EGDI maintains the ability to issue first mortgage bonds, as confirmed in previous hearings, and that these bonds are not covered by a 2X interest coverage ratio new issue restriction.

d) For each of the years 2007 to 2011 inclusive, please provide EGDI’s actual earnings and its interest coverage ratio.

e) Please provide EGDI’s interest coverage ratio for 2013 using a 36% equity ratio and the Board’s Formula ROE.

f) Please list all of EGDI’s financings since January 1, 2007 and provide the amount of time that elapsed between the date information circulars were distributed to the public soliciting support for the investments and the date and time when the investments described therein were fully subscribed.

g) How do the rates that EGDI paid for each of its financings in the period 2007 to date inclusive compare with the cost of debt derived using the formula the Board approved in its December 11, 2009 Cost of Capital Report?

Witnesses: K. Culbert
M. Lister
D. Yaworski

RESPONSE

a) The following summarizes the updated commercial paper forecasted rates for 2012 and 2013:

	2012	**2013**
Forecasted Commercial Paper Rate	1.50%	2.00%

EGDI maintains a $700 million committed credit facility that backstops the commercial paper program. The Company is charged an annual $50,000 administration fee, 0.22% standby fee on undrawn balances and 0.06% fee to extend the maturity date each year. The administration, extension and standby fees are estimated at $2 million annually and amortized over a two year period. In addition, the Company is charged approximately $200,000 per year to maintain the rating coverage in support of the commercial paper credit ratings.

b) EGD is not in a position to comment on the financial arrangements or market accessibility of other companies.

c) Confirmed.

d) Please see the table below:

	2007	**2008**	**2009**	**2010**	**2011**
Earnings (After ESM)	140.1	134.9	140.4	140.3	138.5
Interest Coverage	2.5	2.4	2.5	2.5	2.5

e) The interest coverage ratio for 2013 using a 36% equity ratio would be 2.3, assuming that the 2013 deficiency is recovered and that the difference in equity ratio (from 42%) were financed entirely with short term debt. To the extent that the deficiency were not recovered or that long term debt was used to finance some portion of the difference in equity ratios, then the interest coverage could be significantly lower.

Witnesses: K. Culbert
M. Lister
D. Yaworski

f) The following outlines all the outstanding public term debt financings:

	ENBRIDGE GAS DISTRIBUTION Maturity Date	Years to Maturity	Notional Outstanding	Coupon Rate
MTN	Dec-04-2017	5.96	200,000,000	5.16%
DEB	Dec-02-2024	12.96	85,000,000	9.85%
MTN	Oct-02-2025	13.79	20,000,000	8.85%
MTN	Oct-29-2026	14.87	100,000,000	7.60%
MTN	Nov-03-2027	15.88	100,000,000	6.65%
MTN	May-19-2028	16.42	100,000,000	6.10%
MTN	Jul-05-2023	11.55	100,000,000	6.05%
MTN	Nov-12-2032	20.91	150,000,000	6.90%
MTN	Dec-16-2033	22.00	150,000,000	6.16%
MTN	Sep-24-2014	2.76	200,000,000	5.16%
MTN	Feb-25-2036	24.20	300,000,000	5.21%
MTN	Jan-29-2014	2.11	200,000,000	5.57%
MTN	Dec-17-2021	10.00	175,000,000	4.77%
MTN	Nov-23-2020	8.93	200,000,000	4.04%
MTN	Nov-22-2050	38.95	300,000,000	4.95%
			2,380,000,000	CAD

All public term debt issuances are offered and subscribed to following the governing security law requirements and Canadian debt capital market precedents.

g) The Board's policy for deriving the cost of debt for the electric utilities states:

"The deemed long-term debt rate will be based on the Long Canada Bond Forecast plus an average spread with an A-rated long-term utility bond yield."[1]

The table below compares the cost of debt derived using the Board's formula for the electric utilities and EGD's cost of Debt Financing.

[1] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, Ontario Energy Board, Case # EB-2009-0084, December 11, 2009, p. 59.

Witnesses: K. Culbert
M. Lister
D. Yaworski

	EGD Cost of Debt Financing	Deemed Cost of Debt for Electric Utilities
2007	5.429	5.369
2008	6.035	5.839
2009	5.865	6.176
2010	5.124	5.665
2011	4.708	5.483

BOARD STAFF INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: Ex. E2 /Tab 2/ Sch 1

Please provide a commentary on how the existence of regulatory variance accounts shields the Company from financial risk and therefore neutralizes the requirement for an extra cushion of equity thickness.

RESPONSE

Concentric disagrees that the mere presence of a regulatory variance account would shield the Company from financial risk and therefore neutralize the requirement for an extra cushion of equity thickness. As Concentric has stated on page B-2 of Appendix B in its Report, the greatest risk to a utility from a regulatory perspective is inadequate or untimely cost recovery. Non-recovery or delayed recovery of cost could either be due to increases in costs above those in rates or due to factors beyond the utility's control. Concentric understands that regulators establish variance accounts to capture deviations in costs and revenues, due to factors that the utility is unable to control. However, merely establishing such an account does not result in automatic recovery of costs, but rather earmarks the variance balance for recovery at some future date.

The variance account balance is generally recovered by the utility in a general rate application proceeding, where the costs are scrutinized for prudence and an amortization period is established for recovery in rates. It is not unusual for variance accounts to be amortized into rates over as much as five years or more. It is important to note, that variance accounts may be viewed as increasing risk if it is deemed that recovery of the variance account balance is prolonged or uncertain. It is not the variance account that shields the company from financial risk; it is the timeliness of recovery. Timely recovery of costs is risk-reducing, but the mere existence of variance accounts without the assurance of timely recovery, is not.

Witnesses: J. Coyne
J. Lieberman
Concentric

APPRO INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E1, Tab 2, Schedule 1, paragraph 10

Enbridge proposes to increase the amount of equity from 36% to 42%.

a) At paragraph 10, Enbridge notes that it is proposing to inject $247 million over the course of the 2013 test year. Please provide the proposed schedule of equity infusions.

RESPONSE

Enbridge will manage the amount and timing of equity infusion to conform to the Board Approved Deemed Equity and the requirements of the business.

The schedule for equity infusions will be determined after a decision has been issued by the Board for the equity ratio, capital expenditures, and other issues contained within this application. The timing of the decision may also impact the schedule of equity infusions.

Witness: D. Yaworski

APPRO INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E2, Tab 1, Schedule 2 (Capital Structure)

Enbridge proposes to increase the amount of equity from 36% to 42%.

a) Enbridge indicates that it is exposed to increased business risks. Please redraw the graph in paragraph 2 and include the actual rate of return achieved before any sharing mechanism. Please also provide a table showing by year the actual rate of return and allowable rate of return.

b) Enbridge has indicated that for recognition of the increased risks it ought to have additional equity included in the capital structure. If the additional equity is approved and any of the stated risks (paragraph 7) materialize for which they are requesting additional compensation, is Enbridge also prepared to bear the cost consequences of such risk occurring without recourse to the ratepayers? If not, please explain in detail.

c) Enbridge highlights 3 main factors since 1993 that have increased business risks including: the volumetric demand profile, system size and complexity, and environmental and technological advancements.

   i. With respect to volumetric demand profile risks, for each year that the program was in place, please identify the additional earnings received from DSM programs
   ii. Please confirm that lost industrial volumes due to the implementation of DSM programs are recovered through a LRAM deferral account
   iii. Please confirm that Enbridge voluntarily promotes industrial DSM programs notwithstanding that the OEB in EB-2008-0346 has indicated that ratepayer funded DSM programs for large industrial customers are no longer mandatory.
   iv. Please confirm that all large industrial customers have entered into 12 month or longer distribution contract with Enbridge that protects Enbridge of any revenue losses during the currency of the contract

Witnesses: R. Fischer
M. Lister

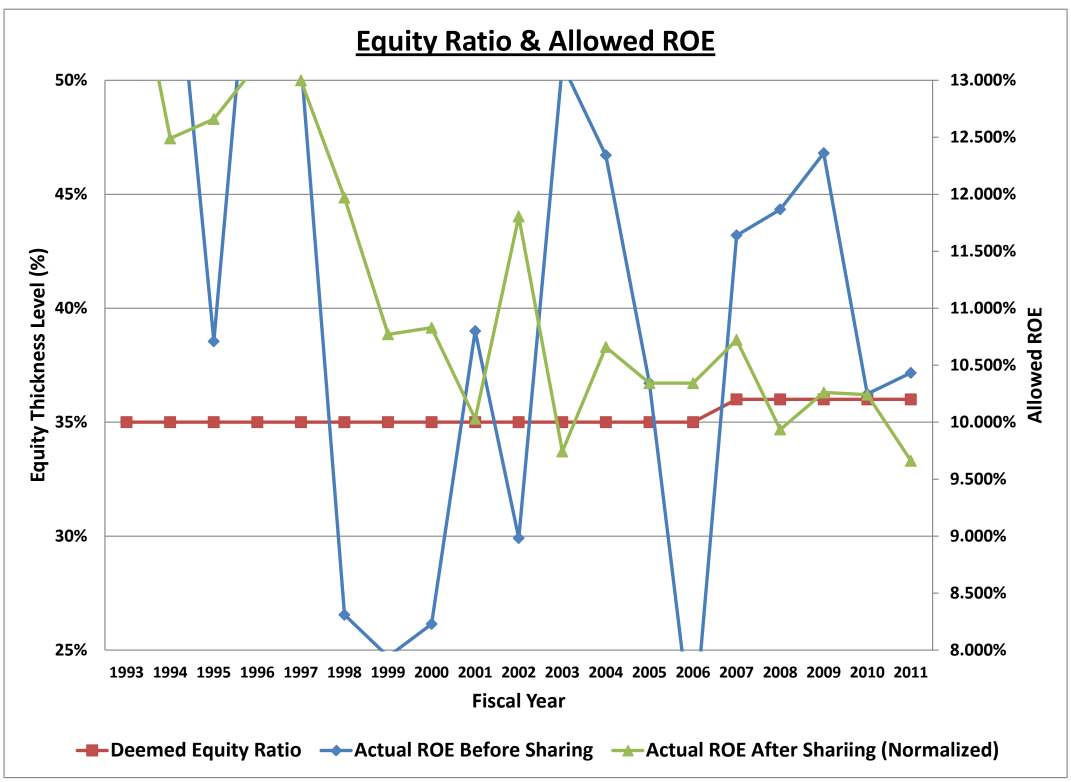
d) With respect to the risks associated with system size and complexity:

  i. Please confirm that from 2000 to 2013 Enbridge added 663 FTEs (40.8%) to assist with managing the growth on their system. If not confirmed, please provide the actual number of additional FTEs added since 2000 to 2013.
  ii. Enbridge indicates that the introduction of pipeline integrity programs has increased risk. Please confirm that pipeline integrity programs are intended to discover potential system problems before a catastrophic event occurs thereby reducing the risk to Enbridge. If not confirmed, please explain.

e) With respect to the environmental and technological advancements and the OPA FIT programs, please confirm that at the burner tip, natural gas has a significant price advantage over the cost of electricity for most applications.

RESPONSE

a) The graph has been redrawn to include the actual rate of return achieved before and after earnings sharing.



Witnesses: R. Fischer
M. Lister

A table showing by the actual rate of return and the allowed rate of return since 1998 can be found in response to CME, CCC, SEC, VECC Interrogatory 1, filed at Exhibit I, Tab E2, Schedule 21.1.

b) EGD's expectation is that moving to a 42% equity ratio and adoption of the fair return standard, will likely either mitigate, or eliminate entirely, the likelihood of consequential costs associated with the identified business and financial risks.

Notwithstanding the above, EGD's position is not simply that a higher equity ratio is needed to mitigate increased business and financial risk, although certainly that is a key tenet of EGD's position. To be clear, EGD's position is that the Company is exposed to greater risk now than it was in 1993, and certainly more than the 1% increase in equity thickness since that time. In addition, the Fair Return Standard is violated if EGD does not increase its equity thickness. The evidence clearly shows much higher equity ratios for comparable firms in the US, which was determined as a reasonable basis for comparison in both this and other jurisdictions in Canada. Further, within this province, electric distribution utilities have an equity ratio of 40%. The evidence shows that the business of gas distribution is riskier than that for electric distribution. Finally, both EGD and credit rating agencies have long noted that the thin deemed equity ratios for Canadian utilities (and EGD currently has the lowest equity ratio) increase risk. This risk would manifest itself in the form of a lower debt rating, and a higher cost of debt. EGD has listened to the rating agencies, and has observed trends across the industry, performed its own analyses and consulted with an expert in producing evidence for the Board to justify a higher equity thickness for the very purpose of minimizing the risk of a downgrade and higher cost of debt.

If there were an increase in equity thickness, and still a credit downgrade were to occur, EGD would seek relief for the higher cost of debt. In this situation would be a clear indication that the business and financial risk are much higher than that embedded in the capital structure, at whatever composition that might entail, which is exactly EGD's point.

c)

i. The performance incentive or Shared Savings Mechanism was first implemented in 1999. With the exception of 2004 and 2005, Enbridge earned a performance incentive for the portfolio of DSM programs as shown on the following page:

1999 - $4.9M
2000 - $3.5M
2001 - $4.6M
2002 - $1.8M
2003 - $2.6M
2004 - 0
2005 - 0
2006 - $10.9M
2007 - $8.2M
2008 - $5.8M
2009 - $5.4M
2010 - $4.2M
2011 - $6.7M

ii. The forecast impact of DSM programs on industrial volumes is built into rates for a given year. The LRAM deferral account adjusts at year end for the difference between the forecast impact and the actual impact of DSM programs on industrial volumes.

iii. Following extensive consultation with stakeholders in 2011, Enbridge submitted to the Ontario Energy Board a DSM plan with an associated Settlement Agreement; the 2012 DM plan included a program for industrial customers with a defined budget cap. This is in keeping with the Board's Guidelines, "... ratepayer funded DSM programs for large industrial customers are no longer mandatory If any are proposed, they will be considered on their merits. The Board defines large industrial gas customers as those in rate classes 100 and T1 for Union and rate class 115 for Enbridge." (Demand Side Management Guidelines for Natural Gas Utilities EB-2008-0346, Ontario Energy Board, June, 2011, page 26)

iv. Large volume industrial customers enter into agreements that stipulate the terms of service, contract demand charges, the terms and conditions of curtailment if applicable, as well as other terms. The agreements do not protect EGD entirely from revenue losses associated with consumption, although partial protection is provided through the minimum bill provision.

d)

i. The table below provides FTE data for the period 2000-2013. However, caution is required when viewing these results. FTE data file in evidence at Exhibit D1, Tab 3, Schedule 1, and in the interrogatory response at Exhibit I, Tab E2, Schedule 2.2, show FTEs measured as the annual average of month-end data for each year. Due to the time limitation required for Interrogatory responses, the Company has not been able to run the reports necessary to obtain the 2000-2006 data on a comparable basis (i.e. 7 years of data, 12 months per year, and 84 data queries). Instead the table below represents FTE data as of the end of each calendar year, so it is only a snapshot as at a point in time. In addition, information on vacancies for the period 2000-2006 is not available, so the data below estimates historical vacancies by applying the average number of vacancies for the period 2007-2011.

	Year-End FTEs		**Average Annual FTEs**
2000	1,475	2007	2,070
2001	1,414	2008	1,943
2002	1,455	2009	1,884
2003	1,698	2010	1,946
2004	1,733	2011	2,084
2005	1,935	Estimate 2012	2,231
2006	1,938	Budget 2013	2,287

ii. The reference to pipeline integrity programs in the evidence can be found at Exhibit I, Tab E2, Schedule 2, page 7, paragraph 22. That paragraph describes the nature of the Director's Orders (2001 and 2006) and then describes why this increases risk for the utility:

> The result has been a large undertaking of labour, resources, and capital on the utility's part to comply with these orders, which ultimately ensure higher operating standards. Being held to higher standards than existed in 1993 is another demonstration of additional incremental risk.

The purpose of the integrity program is to find and fix any potential problems with facilities before there is an incident. Over the long term, EGD believes this will significantly reduce the probability of system

Witnesses: R. Fischer
M. Lister

failures, or catastrophic events. However, over the near and medium terms (10+ years), the program requires more capital and operating expenses than could have been envisioned in the absence of the program. Furthermore, because EGD's assets are primarily underground, inspection of the assets requires either physical digging or in-line inspection (i.e. visual inspection is not possible). EGD has found that the integrity program has significantly increased awareness of faults, corrosion, or leaks. As a result the Company acts swiftly to repair these defects. This can add significant variability to the Company's costs in any given year. The pipeline integrity program acts to improve the safety of the system; the resulting level and variability of costs serve to increase financial risk for the Company.

e) Natural gas generally has a price advantage to electricity for space heating and water heating, but obviously cannot compete with electricity for the myriad of end-uses for which electricity can be applied.

CME INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E1, Tab 1, Schedule 1

The Board conducted a full assessment of EGD's equity ratio in the EB-2006-0034 proceeding which was decided by Reasons for Decision dated July 5, 2007. The Board then determined that a 36% equity ratio was appropriate for EGD.

In the Board's Cost of Capital Report dated December 11, 2009, the Board described its policy and the guiding principles that it will apply in re-assessing the appropriateness of the capital structures for electricity transmitters, generators and gas utilities as follows:

> *"For electricity transmitters, generators and gas utilities, deemed capital structure is determined on a case by case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk."* (emphasis added)

Is EGD attempting, in this case, to have the Board reverse this stated policy?

RESPONSE

EGD believes that its request for an increase in equity thickness is consistent with the Board's stated policy and the Fair Return Standard. The base capital structure has been stable over a long period of time, increasing by only 1% over a period of nearly 20 years. EGD believes there has been a change in the company's business risk, measured on both an absolute basis since 1993, and on a relative basis compared to North American peers and Ontario's electric utilities.

As stated in its evidence, EGD believes that the current equity ratio of 36% is not reflective of changes in business risk over time. That is, in 1993, the equity ratio was

Witnesses: K. Culbert
R. Fischer
M. Lister

set at 35%. Since that time there have been fundamental changes that have increased business risk for gas distribution utilities. EGD believes that the 1% increase in equity ratio from 2007 is neither fully reflective of the increased business risk since 1993, nor reflective of the Board's Fair Return Standard.

Further, EGD's position is that the current equity ratio of 36% is significantly below that of North American peer utilities with comparable business risk and Ontario electric utilities which exhibit lower business risk. Concentric Energy Advisor's analysis shows that Ontario's gas utilities' capital structures have fallen out of line with like-risk peers, and they conclude that the allowed equity ratio for EGD is insufficient and does not meet the standard of fairness. In addition, EGD submits that gas distribution is relatively riskier than electric distribution. Both the Alberta Utilities Commission and a former OEB expert have taken this position (see Exhibit E2, Tab 1, Schedule 2, p.p. 9-11). EGD's position is that the Fair Return Standard requires that EGD's equity ratio should be at least as high as that approved for Ontario electric utilities, on a comparative business risk basis.

Witnesses: K. Culbert
R. Fischer
M. Lister

CME INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E1, Tab 1, Schedule 1

2. In an article in the *Calgary Herald* dated December 9, 2008, Pat Daniels, CEO of Enbridge Inc. and owner of EGD, is reported to have referred to the low risk and steady predictable nature of the pipeline business. Please provide a transcript or any other record available to EGD through its parent, Enbridge Inc., pertaining to the statements made by Mr. Daniels that are referenced in the *Calgary Herald* article.

RESPONSE

Enbridge regularly communicates with investors, the media, and other stakeholders. Media and investor communications information is publicly available at Enbridge Inc.'s website, located at (http://www.enbridge.com/InvestorRelations.aspx).

Enbridge regularly promotes the relatively low risk profile that the pipeline business enjoys. However, this is relative to a broader equity market of competitive firms, and other industries, which experience more volatility than the pipelines business. These firms typically have equity ratios much higher than 42%, as well as greater earnings and ROE volatility. It is not uncommon for a tech firm, for example, to have an equity ratio that exceeds 70% or more.

Nevertheless, recently, at a meeting with Shareholders, Pat Daniel had this to say:

> However, despite all of the efforts of the industry, operating energy infrastructure does come with some risk. And I think we're very aware of that at this particular time. We and the industry need to continue to work to minimize the risk associated with operating major infrastructure like pipelines.

Witnesses: K. Culbert
R. Fischer
M. Lister

> In order to do that, it's important that we recognize conditions that might have contributed to failures in the past and then work to minimize the risk associated with that. That also means adopting advanced leak protection and pipeline integrity management technologies, things that Enbridge works at the most advanced level in doing.[1]

A common theme in all of the communications is the establishment of an appropriate risk-reward relationship. Enbridge's position is that, for the gas distribution business, this risk-reward relationship is not balanced. Specifically, the growth in business risk over time is not consistent with the current equity ratio. Furthermore, the current risk-reward relationship fails to meet the Fair Return Standard. A higher equity ratio is required to bring the risk-reward relationship into balance. Enbridge's position is that a 42% equity ratio is necessary to establish that balance. This recommendation is based on peer group analysis with US firms from Concentric Energy Advisors, a comparison to Ontario's electric distribution utilities, and credit analysis that supports 42% to achieve the right credit metric balance.

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[1] Transcript from Enbridge Day 2010 Analyst Meeting, Toronto, Ontario, October 5, 2010. Available at www.enbridge.com.

Witnesses: K. Culbert
R. Fischer
M. Lister

CME INTERROGATORY #3

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E1, Tab 1, Schedule 1

3. Please revise the calculations in each of these Exhibits to reflect, at lines 5 and 16, the Board approved formula ROE of 7.94% for 2011 and 7.52% for 2012.

RESPONSE

Line No.	2011 Actual	Principal ($Millions)	Component %	Cost Rate %	Return %	Return ($Millions)
1.	Long and Medium-Term Debt	2,319.6	58.62	6.02	3.53	139.5
2.	Short-Term Debt	112.9	2.85	1.61	0.04	1.8
3.	Preference Shares	100.0	2.53	2.40	0.06	2.4
4.	Common Equity	1,424.5	36.00	7.94	2.86	113.1
5.	Total	3,957.0	100.00		6.49	256.8

No.	2012 Bridge Year	Principal ($Millions)	Component %	Cost Rate %	Return %	Return ($Millions)
1.	Long and Medium-Term Debt	2,353.2	57.84	5.89	3.41	138.6
2.	Short-Term Debt	150.8	3.70	2.50	0.09	3.8
3.	Preference Shares	100.0	2.46	3.28	0.08	3.3
4.	Common Equity	1,464.7	36.00	7.52	2.71	110.2
5.	Total	4,068.7	100.00		6.29	255.9

Witnesses: K. Culbert
R. Fischer
M. Lister
D. Yaworsky

CCC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E1/T1/S1

Please provide all materials provided to EGD's Board of Directors and/or to Enbridge Inc. seeking approval to seek an increase in the allowed equity level from 36% to 42%.

RESPONSE

The attached presentation materials were presented to EGD’s Executive Management Team in July, 2011, recommending approval to seek an increase in the allowed equity level. Enbridge Inc. was briefed on the basis of this recommendation. A determination to apply for an increase from 36% to 42% was not made by EGD until approximately November, 2011, once Concentric Energy Advisors had completed their analysis and recommendation.

Witnesses: K. Culbert
R. Fischer
M. Lister

Equity Thickness

Mike Lister, Ralph Fischer

ENBRIDGE

Equity Thickness

- **2006 Backgrounder**
- **Equity Thickness Impacts**
- **North American Industry**
- **Concentric opinions & thoughts**
- **Thoughts, insights from Treasury**

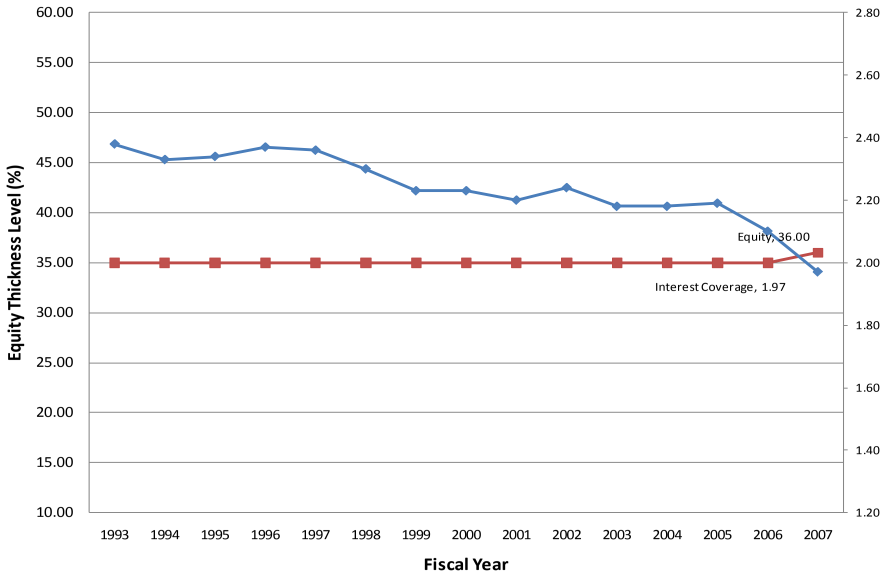
2006 Backgrounder

- Main position centred on two themes:
  - → Increased Risk Profile since 1990 (when 35% was established)
  - → Forecast difficulty in meeting coverage ratios

Higher Risk Environment (since 1990):

- Natural gas prices & volatility
- Increase conservation efforts and impacts
- DSM impacts
- Appliance uses and standards
- Trend towards multiples, away from single, detached dwellings
- Different housing price dynamics

Board Approved Equity Thickness & Interest Coverage

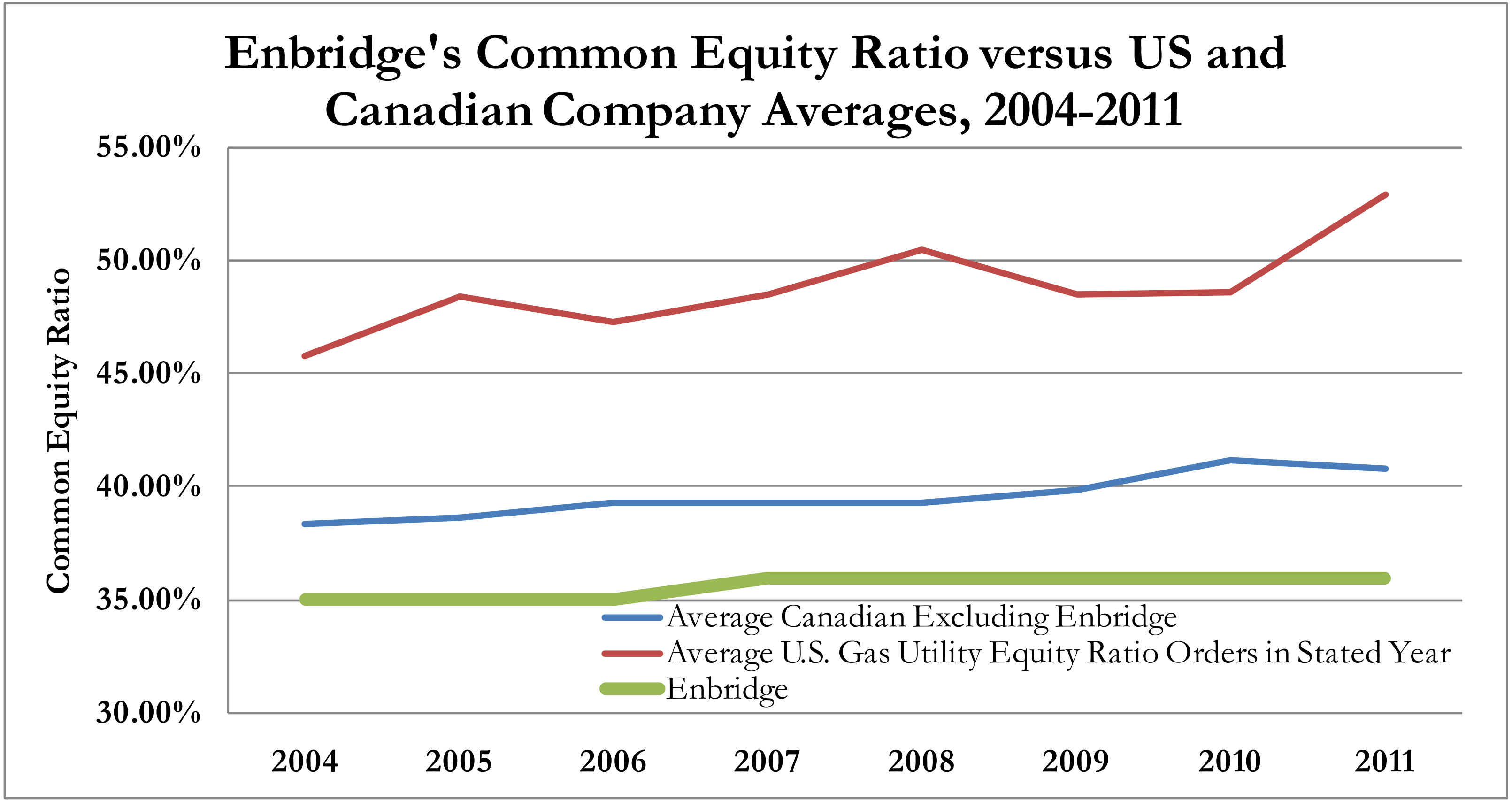


Equity Thickness Impacts

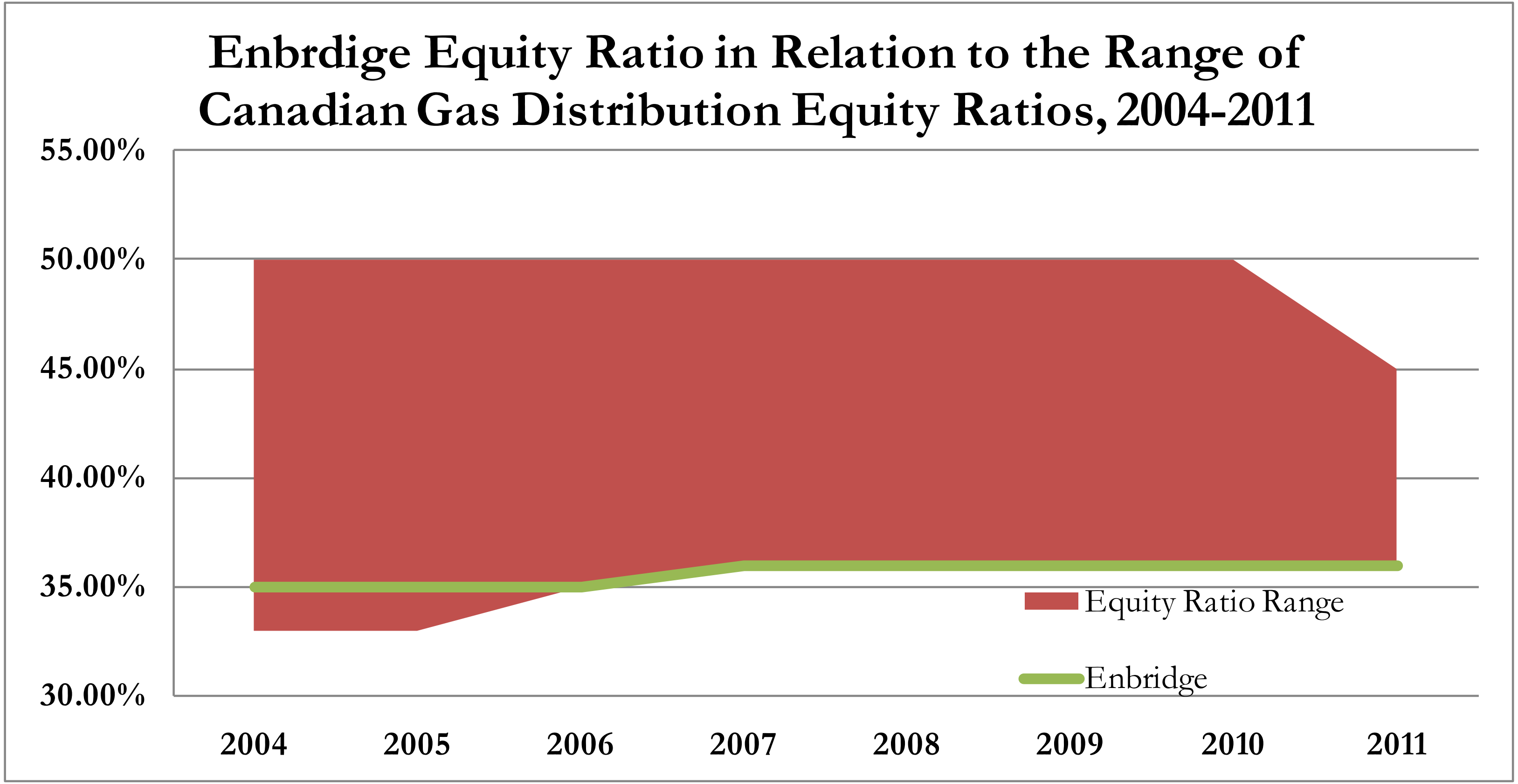
Rate Base	ROE	Equity Thickness	Annual After-Tax Earnings Impact
$4,000 M	10 %	36 %	$144 M
$4,000 M	10 %	40 %	$160 M
		Difference	$16 M
		Difference per 1%	$4 M

- → **Union Gas will ask for Equity Thickness of 40% in 2013**
- → **Ontario Electrics currently at 40% Equity Thickness**
- → **Alberta and TQM decisions say gas distribution is riskier than electrics; 2009 case, EGD argued we were riskier than electrics**

Canada, U.S.A., Enbridge



Enbridge: Bottom of the Pack



Pros/Cons of More Equity (Concentric opinion)

Pros

- Improves earnings and financial ratios, and strengthens credit ratings
- Potentially lowers cost of debt
- Provides greater financial flexibility for major projects, cushion for unanticipated events, or distribution up to Enbridge Inc.
- Brings Enbridge into conformity with other Canadian LDCs
- Better aligns Board allowed ROE with equity ratio
- Timing – currently lower gas prices provides rate headroom, and financial crisis reinforced value of liquidity

Cons

- Increases rates
- Expectation that Enbridge Inc. will infuse the equity – is this the best use of equity capital?
- Might see Board/stakeholder resistance to move from current ROE of 8.39% to generic rate of 9.58%, along with more equity
- Potentially weakens settlement "gives" by stakeholders on other issues (e.g., IR terms)

Thoughts, Insights from Treasury

- Increased equity ratio could deliver improved debt ratings and reduced debt/issuance costs
- However, debt rates are at historic lows and are likely to increase by at least 100 basis points over the next four years
- With an equity ratio increase, best case scenario is neutral impact to future debt rates, though higher debt rates are more likely
- To achieve the higher equity %, EI would inject equity and leave distribution policy unchanged

Recommendation

- Prepare a case to present to the OEB for a higher equity thickness (likely 40%)
  - Draft & finalize a scope and project budget cost for Concentric to represent EGD
  - Use Company and Consultant resources to build case around several main themes:
    - Relative increase in risk environment since the early 1990s
    - Risk of downgrade vs. cost of equity thickness
    - Comparison of EGD to Canadian and US Gas LDCs
    - Application and maintenance of the Fair Return Standard
  - Prepare Checkpoint presentation for the EMT ~early September
  - Have draft evidence prepared ~late September

Questions / Feedback

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

E – Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: Exhibit E2, Tab 1, Schedule 2

If the Board determines that there has been a significant change in the company's business and/or financial risk, does EGD agree that in addition to the change in the equity component of the capital structure, the long term debt, short term debt and preference share components of the capital structure should also be reviewed and moved more in line with the electricity distributors? If not, please explain why not.

RESPONSE

EGD understands that the Ontario Energy Board (the “Board”) established the policy for the determination of the long term debt component of the capital structure for Ontario’s electricity distributors in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors, issued on December 20, 2006. In that Report, the Board determined that a common equity ratio of 40% was appropriate for all of the Provinces’ electric distribution utilities, and that the debt component would comprise the other 60% of total capitalization. From within this 60% debt amount, 4% would be deemed short term debt, and the remaining 56% would be long term debt.

Specifically, the Board states:

> The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. The short-term debt amount will be fixed at 4% of rate base.

The 4% was determined as, “the actual average for the industry”.

Witnesses: R. Fischer
M. Lister
D. Yaworski

In opining on the options considered in that case, the Board determined that,

> another option would be to use the actual short-term debt expressed as a percentage of the distributor's capital structure. Although using a distributor's actual short term debt component may seem to be a more accurate approach, it may be problematic. Short-term debt is optimally used as an interim solution for managing a firm's financing requirements. It may fluctuate, although generally within a limited range. Using a firm's actual short-term debt component would be administratively challenging given the number of electricity distributors and the associated volume of data that would need to be reported and verified.

Given that there are essentially two large gas distributors, and therefore the associated volume of data that would need to be reported and verified is very small, EGD no need to change the policy from that which currently exists if the Board determines that a higher equity component of the capital structure is reasonable.

Regarding the use of preference shares, in the December 20, 2006 Cost of Capital report for the electric utilities, the Board determined that there would be no adjustment for a preferred share component of equity in rates. Conversely, the gas utilities have been employing preference shares since before 1993, and EGD sees no reason to discontinue this structure.

Witnesses: R. Fischer
M. Lister
D. Yaworski

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

E – Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: Exhibit E2, Tab 1, Schedule 2

a) When is the last time the OEB approved the common equity ratio for EGD?

b) Please provide the percentage of total distribution revenue (excluding gas costs) that was recovered through each of monthly fixed charges, firm demand charges and variable volumetric rates in 1993 and 2011. If data for 1993 is not available, please provide the percentages for each year in 2007 through 2011.

c) Does use of the AUTUVA account eliminate the risk associated with residential average use consumption for all drivers but weather? Please explain any other risks, other than weather, that remains with the AUTUVA.

d) Does the AUTUVA account apply solely to Rate 1 customers? If not, what other rate classes does it apply to?

e) Has EGD considered the use of a true up account for industrial demand? If no, why not? If yes, please explain why EGD has not proposed such an account in this proceeding.

f) With respect to the System Size and Complexity, is it EGD's position that because it is bigger it has more risk and therefore requires a higher common equity ratio? If yes, does this mean that if EGD were split into 2 smaller companies, both would have less risk, and therefore a need for a lower common equity ratio?

g) Are the figures noted in paragraph 21 in real or nominal dollars? If they are in nominal dollars, what has been the cumulative increase in inflation between 1993 and 2013?

Witnesses: R. Fischer
M. Lister
D. Yaworski

RESPONSE

a) Please see the response to VECC Interrogatory 1, filed at Exhibit I, Issue E2, Schedule 20.1.

b) In 1993, the forecast amount of distribution revenue recovered from fixed charges was 18%. For 2011, the forecast amount of fixed charge recovery was 52%.

c) The Average Use True-Up Variance Account ("AUTUVA") was the result of a negotiated settlement as part of the Incentive Regulation Framework. Its purpose is to protect both small volume consumers and the Company from any variances from forecast volumes for a given test year. The following table highlights the AUTUVA account true-up revenue balances over the 2008-2011 (proposed) years:

($ Millions)				
	2008	2009	2010	2011*
Rate 1	1.48	2.53	4.59	4.86*
Rate 6	(4.13)	3.09	(6.74)	(7.81)*
Total	(2.65)	5.63	(2.15)	(2.95)*

*Pending Board Approval

As can be seen the typical balances have been small, and on an aggregate basis have protected consumers for forecasts that would have resulted in otherwise higher charges.

As explained in the Company's evidence, since 2007, the AUTUVA has helped mitigate the impact of uncertainty around declining average use. The AUTUVA ensures that revenues are not impacted by variances from the forecast average use decline. If the actual average use decline is less than forecast, then customers are credited for the difference through the disposition of the variance account. Alternatively, if the actual average use decline is greater than forecast, then customers are debited for the difference.

Thus, the AUTUVA minimizes the intra-year revenue impact associated with the uncertainty of actual residential average use declines compared to the forecast; however, it does not address the longer-term implications that result from a trend of declining average use.

Other risks besides weather that can impact the business include cost variability that could arise as a result of ageing infrastructure or safety issues, training, the price of materials, the movement of interest rates or utility credit spreads, the costs of labour,

Witnesses: R. Fischer
M. Lister
D. Yaworski

the costs related to insurance, litigation, or bad debts, the ability to generate other revenues as forecast, the economic impacts on volumetric demand generally, or on industrial uses in particular. There are risks associated with an ageing workforce, with technical, safety or compliance standards as well as operational risks associated with a massive inventory of underground facilities of varying vintage, including pipes fittings, valves, or pressure stations. There are risks associated with third party damages, employee health and safety, or environmental and physical risks, and the associated costs, associated with ruptured or leaking infrastructure. There is also the risk that other outside influences may have on consumption patterns such as weather, the demand for gas across North America, the availability and access to supply, storage spreads, the price of fuel oil, or other energy alternatives. There are also risks associated with the advancement of other forms of energy technologies, or with regulatory or legislative impacts on either the revenue or the cost side. This list of risks is not necessarily exhaustive and may include others as well.

Aside from the list of absolute risks, the Fair Return Standard states that the cost of capital should represent an amount that is commensurate with investment of like risk. On a relative basis, it is the Company's position that the gas distribution business is riskier than the electric distribution business. Both the gas and electric utilities in Ontario use the same ROE formula to derive ROE, and yet the Ontario electric utilities have equity ratios that are higher than the gas distribution equity ratios. Furthermore, the Company's equity ratio is not consistent with investments of like risk based on a carefully constructed US peer group analysis, or with other utilities across Canada.

d) No, the AUTUVA account does not apply solely to Rate 1 customers. The AUTUVA also applies to Rate 6 customers.

e) No, EGD has not considered a true up account for industrial demand.

The AUTUVA is designed to remove any variance from forecast average use impacts related to small volume customers. This is facilitated by the ability to accurately forecast small volume average uses. Small volume average uses can be forecast with a high degree of accuracy because of the homogenous customer characteristics of rate 1 and rate 6 customers, respectively, and the relatively easy to identify forecast driver variables (i.e. gas prices, heating stock vintage, economic activity, etc.). Conversely, industrial volumes by their nature are much more difficult to predict. There are many more rate classes that are comprised of a heterogeneous group of customers ranging from retail outlets, to large scale manufacturing with natural gas used in the manufacturing process. Also, the drivers of demand for these customers might not be as consistent as that which exists for the small volume classes. That is, demand in specific industries may be affected by industry specific events or circumstances.

Therefore, the ability to forecast average industrial volumes is much lower than that for small volumes, and the practicality of administering an AUTUVA related to industrial load would be very difficult. There is a very high probability that such an account would result in very volatile and unpredictable amounts for true up, which would result in greater rate volatility, and greater rate shock. This, in turn, would upset customers. EGD would also be concerned if hard or soft caps were introduced to alleviate any negative rate shock, exposing the Company to additional risk, with no apparent upside.

Alternatively, the rate impacts associated with the Rate 1 / Rate 6 AUTUVA account have been relatively small, and in favour of EGD's ratepayers.

f) Please see the response to CME, CCC, SEC, VECC Interrogatory 3, filed at Exhibit I, Issue E2, Schedule 21.3 for a response as to the Company's position with respect to business risk and system size.

g) The figures noted in paragraph 21 are in nominal dollars. Please see the response to CME, CCC, SEC, VECC Interrogatory 3, filed at Exhibit I, Issue E2, Schedule 21.3 for a representation of the same figures in paragraph stated in 2012 dollars.

Witnesses: R. Fischer
M. Lister
D. Yaworski

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

E – Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: Exhibit M1, Tab 1, Schedule 5

a) If the Board determined that the equity ratio should be maintained at 36%, what other changes to the capital structure would EGD propose? In particular, what long term and short term debt components would be proposed by EGD?

b) If the long term debt component of the capital structure would be increased, please provide a forecast of the incremental long-term debt that would be issued in 2012 and/or 2013 and provide the forecast rate for this incremental debt and show the forecast of the total cost of the long term debt in the 2013 test year.

c) Please provide a version of the deficiency calculation showing the deficiency if the common equity component remained at 36% and the other components of the capital structure were adjusted to reflect the changes noted above.

RESPONSE

a) The Company has not planned for incremental long term debt issuances. As a result analyses presented in interrogatory responses assumes the swing would occur from the equity ratio to the short term debt component.

b) Please see the response to part a) above.

c) Subject to the constraints raised in part a) above, the requested information is provided below.

Witnesses: K. Culbert
M. Lister
D. Yaworski

UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	2,312.8	56.36	5.90	3.325
2.	Short-Term Debt	213.5	5.20	3.70	0.192
3.		2,526.3	61.56		3.517
4.	Preference Shares	100.0	2.44	4.16	0.102
5.	Common Equity	1,477.3	36.00	9.03	3.251
6.		4,103.6	100.00		6.870
7.	Rate Base	($Millions)			4,103.6
8.	Utility Income	($Millions)			237.5
9.	Indicated Rate of Return				5.788
10.	Deficiency in Rate of Return				(1.082)
11.	Net Deficiency	($Millions)			(44.4)
12.	Gross Deficiency	($Millions)			(60.4)
13.	Customer Care/CIS Deficiency	($Millions)			(11.0)
14.	Total Gross Revenue Deficiency	($Millions)			(71.4)
15.	Revenue at Existing Rates	($Millions)			2,319.7
16.	Revenue Requirement	($Millions)			2,391.1
17.	Gross Revenue Deficiency	($Millions)			(71.4)

Witnesses: K. Culbert
M. Lister
D. Yaworski

SEC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/1/2, p. 2, 12

Please provide all communications from any rating agency or other third party to the Applicant dealing with the possibility that the Applicant or its parent company will have a credit downgrade. Please provide all other evidence in the Applicant's possession showing that there is a risk of a credit downgrade.

RESPONSE

EGD does not possess any direct communication from a rating agency or other third party dealing with the possibility of a credit downgrade. Rating Agencies would not (could not) indicate a downgrade publicly prior to any action actually being taken.

The evidence in EGD's possession showing that there is a risk of a credit downgrade includes the volume of materials that EGD and its expert have provided in pre-filed evidence and interrogatories. The main points can be summarized as:

- Higher business risk since 1993
- Access to the ratings methodologies of the credit rating agencies, and the credit rating reports
- Public statements from Credit rating agency participants, industry experts, and regulators that indicate the need for higher equity thickness among Canada's gas utilities:
    - The Lackenbuer & Engen evidence referenced in the evidence at Exhibit E2, Tab 1, Schedule 2, p. 12, paragraph 34 (please see Exhibit I, Issue E3, Schedule 1.4, Attachment 2)
    - A presentation given at the Canadian Association of Municipal & Public Utility Tribunals (CAMPUT) in 2003 by DBRS (please see Exhibit I, Issue 3, Schedule 1.4, Attachment 1)

Witnesses: R. Fischer
M. Lister
D. Yaworsky

- A National Economic Research Associates, Inc. paper commissioned by the Canadian Gas Association in 2008 that analyzes the economic, financial, and institutional differences in risk between the Canadian and U.S. regulatory structures (Attachment 1)
- A decision in the Fortis BC (Teresan Gas) application, that was the subject of a case for Terasen very similar to EGD's case and provides a regulator's perspective (Attachment 2)
- A 2009 decision by the Alberta Utilities Commission in which they assess the relative risk of forms of energy delivery (later reaffirmed in 2011) (Attachment 3)
- Commentary by the Director of Corporate Bond Research at Scotia Capital to the Ontario Energy Board (please see Exhibit I, Tab E3, Schedule 1.4 Attachment 4)

- The assessment provided by Concentric Energy Advisors, and produced in evidence at Exhibit E2, Tab 2, Schedule 1

Witnesses: R. Fischer
M. Lister
D. Yaworsky

Allowed Return on Equity in Canada and the United States

An Economic, Financial and Institutional Analysis

National Economic Research Associates, Inc.
Kenneth Gordon, Ph.D
Jeff D. Makholm, Ph.D

MMC Marsh & McLennan Companies

February 2008

This study was commissioned by the Canadian Gas Association.

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I. INTRODUCTION[1]

Canada and the United States have almost hundred-year histories of regulating investor-owned utilities. This shared experience is different from almost all of the rest of the world, where the appearance of investor-owned (i.e., private) utilities came only with the privatization wave of the late 20th century. The regulatory laws, mechanisms and institutions in those other countries are new—and in many cases untested. But longstanding regulatory institutions in Canada and the US have for decades been helping to provide safe and adequate services to the public at reasonable prices while ensuring that the companies involved remain "going concerns" with sufficient credit worthiness to attract the capital needed to maintain and expand their facilities.

Over the past decade, however, a significant difference has appeared in the regulatory practices between Canada and the US. In an effort to improve regulatory efficiency, Canadian regulators—first in British Columbia, then more widely—moved away from the case-by-case approach to determining the fair return on equity (ROE) for utility rate making purposes. Canadian regulators adopted generic, formula-based approaches to deriving the admittedly elusive fair ROE. US regulators in the 1980s and 1990s made two tries at generic, formula-based approaches to setting the ROE (one at the federal level and one in the State of New York), but, in the end, did not abandon their longstanding, case-by-case methods that rested on two existing and long-accepted financial theories.

The apparent efficiency of bypassing case-by-case evidentiary proceedings with a generic formula may have foretold a new and more efficient method of deriving regulated rates generally—except for one thing. The current Canadian generic ROE formula appears to have created a persistent divergence between allowed gas utility returns in Canada and the US. Since 1998, ROEs used to make regulated tariffs have been, on average, 100 to 150 basis points lower than in the US. That is, in dozens of evidentiary proceedings since 1998, US regulators have allowed their companies to set tariffs reflecting ROEs that were on average substantially higher than for their Canadian formula-driven ROE counterparts.

The purpose of this report is to analyze the root causes of this disparity between Canadian and US ROEs that has apparently been propelled—either directly or indirectly—by the Canadian ROE adjustment formula. Since the "appropriate" level of ROE is driven by the risk/return requirements of those utility investor-owners, the obvious question is whether Canadian utilities face sufficiently less risk than their US counterparts. Conversely, we investigate whether the difference in allowed returns for ratemaking is merely a symptom of a structurally inflexible formula rather than an indicator of underlying risk differences. If it is the latter, then Canadian regulators have indeed streamlined rate cases for the better. If the former, then perhaps the formula has had unintended consequences and is in need of updating better to reflect the market's judgment on the cost of equity of regulated Canadian utilities.

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[1] This report was written by NERA's Kenneth Gordon, Special Consultant and former Chairman of the Department of Public Utilities Massachusetts and the Public Utility Commission in Maine and Jeff D. Makholm, Senior Vice President. They were supported by Ryan Knight at NERA.

It is important to state at the outset how we approach examining this divergence We cannot automatically presume that the burden falls on Canadian regulators to justify the persistently lower average ROEs than those granted by their US counterparts. Nevertheless, it is the group of Canadian regulators that changed course in the last decade, led by those regulators using the generic formula for streamlined regulatory procedures. Those regulators in the US who failed to find a suitable way to streamline their ROE procedures continued on the former path common to both Canadian and the US regulation—to examine anew, in every tariff case, expert evidence on ROE for the company in question for the relevant period of time. We do not believe that either Canadian or US regulators would consider the results of those case-by-case evidentiary procedures to be biased on a large scale. They are perhaps expensive, time consuming or overwrought—but not biased. Therefore, it is natural—and again to us justifiable—to subject the new Canadian generic formula to the test of bias. If we find that Canadian and US utilities face comparable operating environments and risk to investors, then it is natural to question the efficacy of the new Canadian formula approach to the ROE, not the traditional path US regulators still hold. It is therefore not prejudgment that prompts us to examine underlying justifications for the new and lower Canadian ROEs, but practicality. We do not question whether US regulators (or Canadian regulators up to the adoption of the new formula) were incapable of deriving "just and reasonable" tariffs. What we do question is whether, based on underlying risk factors, the new Canadian generic ROE formula can do likewise.

Canadian regulators have acknowledged in rate cases that a disparity exists between Canadian and US allowed ROEs, but have not concluded whether or not the disparity warrants action.[2] For example, the regulator in Quebec, the Regie de l'Energie, stated in 2007, "[i]n the Regie's view, even though rates of return allowed in the United States are clearly higher on average than those allowed in Canada, the evidence does not make it possible to conclude that there is any prejudice to or unfair treatment of the distributor.... The evidence does not make it possible to compare the overall differences that may exist in the institutional, economic and financial contexts of the two countries and their impact on the opportunities they provide for investors." [3]

Unfortunately, nothing surrounding the required ROE for the purpose of making regulated tariffs is an easy discussion. Unlike the other elements of tariff setting (operating costs, maintenance costs, administrative expenses or the interest rates on utility bonds) the ROE is not directly observable. The required ROE is a function of investor *expectations*. Those expectations remain complex functions of how investors believe that price regulation, along with the utility's other circumstances, will work to allow them a return on the capital that they devote to serving the public. Given the complexity associated with discussion of the fair ROE, this report will examine the root of the post-1998 differences in permitted ROEs. Those differences stem either from corresponding differences in risk in Canada versus the US or from more banal causes relating to the operation of the generic ROE formula itself vis-à-vis investors' genuine risk-driven expectations.

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2 *See*: Ontario Energy Board (OEB) *A Review of the Board's Guidelines for Establishing Return on Equity* RP-2002-0158 (2004) ¶ 122. *See* also: Alberta Energy Board (EUB) *Generic Cost of Capital* Decision 2004-052 (2004) pgs 25-27.

3 Regie de l'Energie, *Decision: Application to Modify the Tariffs of Gaz Metro Ltd*. D-2007-116 (2007) §4.1.10.

The report concludes that the regulatory environments in Canada and the US are highly similar and directly comparable. Since the world's first utility commission regulatory statute was written in the US in 1907 in Wisconsin, that general form has been widely copied in all states and provinces in Canada and the US.[4] These two national jurisdictions thus share a common heritage that is quite different, for example, from the newly-privatized regulatory jurisdictions in the rest of the world. Those jurisdictions overseas regulate their investor-owned utilities on an institutional basis quite different than in Canada and the US—two countries that share the longest, largest and most unencumbered trade border in the world. It is thus a fair question to compare and contrast Canadian and US utilities with each other to examine how their regulators deal with them and, in particular, derive the ROEs used to set their regulated tariffs.

Section II contains our Executive Summary. In **Section III**, we examine the evident divergence between allowed returns in Canada and the US that propels this study. In **Section IV**, we compare the methods used for setting base ROEs in Canada to the case-by-case methods still used by US utility regulators, despite two highly visible attempts to create generic formulas there. In **Section V**, we examine the sources of risk for regulated utilities and any apparent differences between investor-owned utilities in Canada and the US that might, in principle, explain the wedge in ROEs that has appeared since 1998.

[4] That statute was drafted by John R. Commons, a professor of economics at the University of Wisconsin and 10 years later the President of the American Economic Association.

II. EXECUTIVE SUMMARY

In the introduction to this report, we stated that we do not automatically presume that the burden falls on Canadian regulators to justify the persistently lower ROEs allowed relative to their US counterparts. First, those numbers may not fairly gauge the treatment of Canadian gas distributors on the part of regulators. Second, those ROEs may combine with other aspects of Canadian financial markets or regulatory procedures that do not generalize to the US. Third, the relative ROEs may reflect business, regulatory, or financial risk differences for Canadian gas distributors versus their US counterparts.

Taking these elements into account, however, it is our opinion that the generic Canadian formula itself should be the subject of scrutiny. The formula works like an "autopilot" for setting new Canadian ROEs that uses long bonds as the only contemporary gauge of financial markets—instead of directly targeting equity costs. If the new autopilot has been setting a different course than the case-by-case "human" pilots that previously characterized Canadian ROE, and still characterize US ROE setting, then the autopilot should bear the burden of showing that it is not biased. We cannot conclude going in that the group of independent regulators setting their own ROEs on a case-by-case basis are the ones to be exhibiting a bias.

Figure 1 in our report, showing a marked split in the allowed ROEs in Canada and the US, demands the examination of three issues regarding the meaning and comparability of the relative ROEs before the question of whether the Canadian formula has exhibited a bias in recent years can be addressed:

- We explain that under both Canadian and US regulatory methods, the ROE is the measure of cost of capital that enters the formula to make "just and reasonable" rates. It is the measure of compensation allowed for the capital that investors devote to the service of the public *at the time rates are set*. What happens afterward—in other words, what the utilities actually achieve in profitability—is a different matter. The actual returns reflect many things including management effectiveness, sales growth, the weather, macroeconomic considerations, changes in capital costs, etc. But regulatory treatment of investor-owners is tightly bound to the ROE. We conclude that allowed ROE is the proper metric for comparison.

- We find that the regulatory institutions and customs for setting regulated prices for investor-owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions, unlike newly-privatized utilities in new regulatory jurisdictions overseas, where regulatory institutions are young (and largely untested),. There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the

US.[5] As such, the cost of equity capital is comparable between the two countries as long as the risk of gas distributors is the same or similar on both sides of the border.

- We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences shown in **Figure 1**.

With this analysis, our conclusion is inescapable. The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But is has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs.

The manifest remedies are either to return to "human" pilots (representing case-by-case ROE determinations) or re-calibrate the Canadian generic formula by re-examining the current relationship between the contemporaneous cost of debt and gas utility equity. Given the similarity in the jurisdictions, the institutions of regulation and capital markets, it would be useful in our opinion to employ both Canadian and US gas utility equities in such an analysis, along with both of the main cost of equity models (DCF and CAPM). Without a new calibration, it is likely that as long as the interest rates in Canada and the US remain low, the generic ROE formula will continue to fly off course—essentially treating Canadian utility investors unfairly and slowly taxing their financial health in this era of low interest rates.

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[5] If one threw all 63 federal and provincial/state regulatory statutes (13 for Canada, 51 from the US) into one pile with all the names blacked out, we would challenge anyone to sort them into a Canadian or US pile based on their content alone.

III. AN EVIDENT DISPARITY IN CANADIAN AND US ALLOWED RETURNS

This report is propelled by the need to examine the persistent gap between the allowed returns on equity for ratemaking purposes between Canadian and US regulators.[6] This section examines what the divergence is and where it comes from. It examines whether the ROE figures in Canada and the US are both a reasonable and comparable metric for determining effective regulatory control over profitability in both countries, and also describes how the Canadian ROE formula works.

There are two key questions. First, does the divergence mean anything? Is the ROE (as opposed to earned returns) the right metric for comparison? Second, are the economies comparable enough (given differences in taxes, etc.—everything but regulatory risk) to permit ROE comparisons.

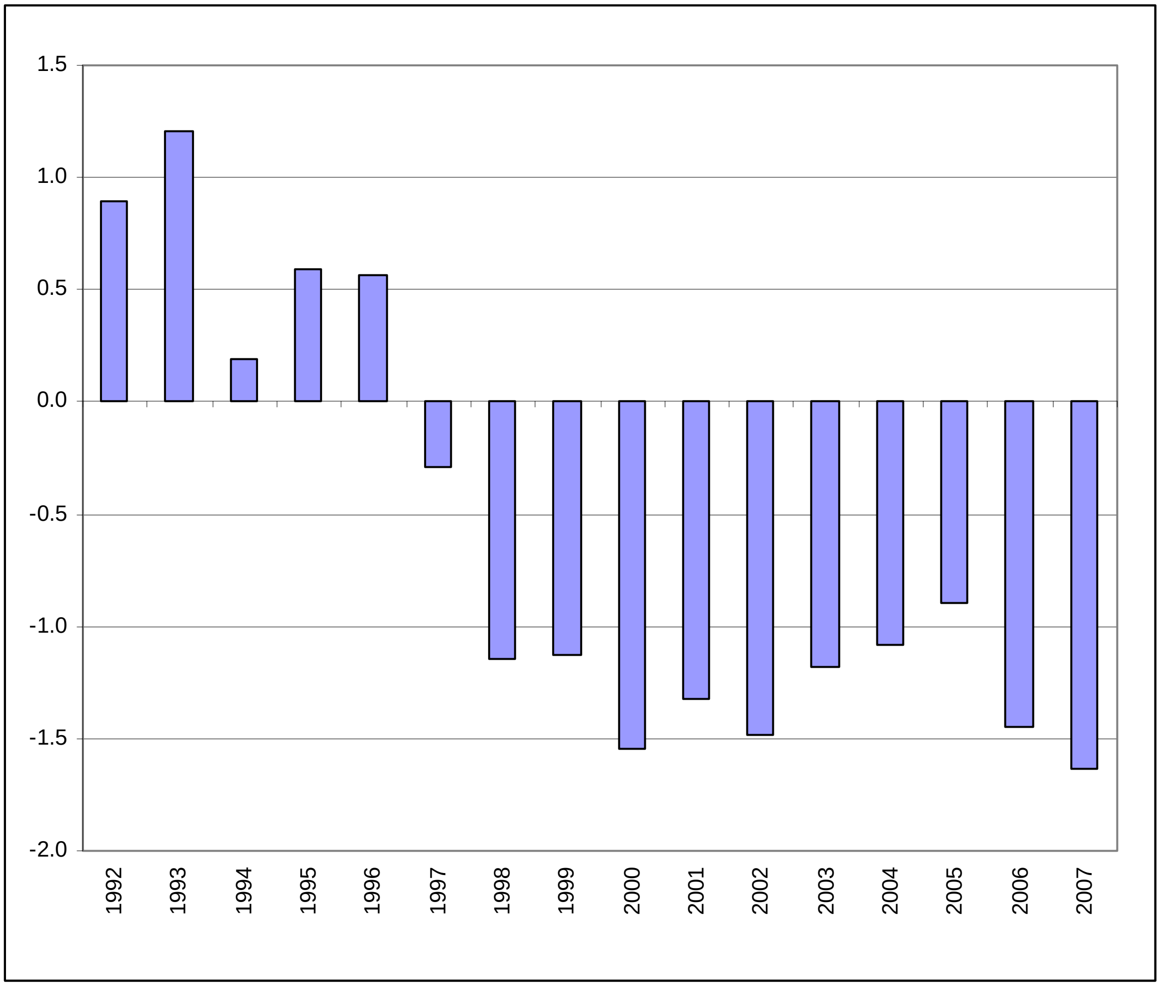
A. The Divergence between Canadian and US Allowed Returns for Ratemaking

Figure 1 shows that Canadian allowed returns were, at one time, higher than those allowed in the US, but that this changed during 1997. Since then, Canadian allowed returns have been markedly lower than those in the US.

Figure 1 was compiled using data submitted by members of the Canadian Gas Association (CGA) for Canada and data gathered from Regulatory Research Associates for the US. The CGA submitted data for 8 Canadian LDCs, although data were not available for every LDC for every year. The number of rate case decisions for US LDCs for which Regulatory Research Associates data were available varies from 10 in 1999 to 42 in 1993. The data used to construct Figure 1 is presented in **Table 1** below.

[6] It is important to keep in mind that “allowed returns” (i.e., ROE) means the rate of return equity, permitted in a rate case proceeding, to form a component of regulated prices. It does not refer to an attempt by regulators to control the return on capital actually earned by utilities once those rates are set. Ratemaking in Canadian and US jurisdictions is generally a *prospective* exercise.

Figure 1: Allowed Return Average Differential (Canada-US) for Gas Distribution Utilities, 1992-2007



Source: Canadian Gas Association, Regulatory Research Associates.

- **Figure 1** was generated by subtracting the average allowed US ROE from the average allowed Canadian ROE for each year. This differential for Canada ranges from 121 basis points above US ROEs in 1993 to 164 basis points below in 2007. Starting in 1997, the differential has been consistently negative; indicating that, over the past decade, average allowed US ROEs are higher on average than those in Canada. These average allowed ROEs for both countries are presented on **Table** 1.

Table 1: Canada-US Average Allowed Return Differential, 1992-2007

	Canada	US	Difference
1992	12.88	11.98	0.89
1993	12.58	11.37	1.21
1994	11.44	11.24	0.19
1995	12.03	11.44	0.59
1996	11.68	11.12	0.56
1997	11.01	11.31	-0.29
1998	10.38	11.52	-1.15
1999	9.52	10.64	-1.12
2000	9.80	11.35	-1.55
2001	9.64	10.96	-1.32
2002	9.61	11.10	-1.48
2003	9.79	10.97	-1.18
2004	9.55	10.63	-1.08
2005	9.52	10.41	-0.89
2006	8.99	10.43	-1.45
2007	8.71	10.35	-1.64

By the simple metric of average ROEs in Canada and the US, a clear disparity has emerged. This disparity was the subject of a recent report by Concentric Energy Advisors, which examined the disparity between Ontario LDCs and US LDCs in particular. The Concentric Report concludes that Canadian ROEs were more sensitive to the drop in bond yields over this period than were US ROEs.[7] Further, the Concentric Report suggests that this sensitivity arose through the adoption of an automatic adjustment mechanism that explicitly ties Canadian ROEs to long-bond prices.[8]

B. Is Allowed ROE the Proper Metrics for the Comparison of the Treatment of Utilities by their Regulators?

A threshold question is whether the figures in Table 1 mean anything in terms of assessing regulatory treatment in Canada versus the US. That is, given the unique economic and financial contexts of each country, are ROEs structurally different such that an allowed return in the Canada does not mean the same thing as an allowed return in the US?

Three issues arise in answering this question. First, is the ROE the proper metric, as opposed to the return that the utilities in question have actually achieved during the period of time the rates were in effect? It is a question that arises often in comparison of ROEs. Second, does capital flow freely between countries? If capital does not flow between countries, allowed returns are

7 Concentric Energy Advisors, "A Comparative Analysis of Return on Equity of Natural Gas Utilities," prepared for Ontario Energy Board (2007). p. 2.

8 *Id.*, p. 56.

likely to not be comparable as capital costs would reflect strictly national macroeconomic considerations. Third, given the distinct tax and financial environments, such as differences in country-specific interest rates, are allowed returns similar indicators in both Canada and the US? This section examines these issues in turn.

1. Allowed ROEs versus Achieved Returns

Is the allowed ROE the proper metric, or are the returns that the utilities in question have actually achieved during the period of time the rates were in effect the relevant indicator? We readily conclude that the answer is yes: allowed ROEs are the proper metric. Both in Canada and the US, the general manner of regulatory control is for regulators to set *reasonable rates* and then allow utilities to do the best they can to make a business and earn a reasonable return against those rates. That is to say, utilities in Canada and the US are not cost-plus businesses that can appeal to cover costs after the fact. Utilities are not confined to any particular return. There are admittedly exceptions (which we consider idiosyncrasies) to this general statement—but the character of ratemaking control in both countries is prospective.

For over a century, both in Canada and the US, the pull between private enterprise and the public welfare has been settled just this way: regulators deem the return to be considered "just and reasonable" and the private utility subsequently does its best to profit—until such time as the regulator or the utility request that the question of the forward-looking just and reasonable rates should be adjudicated again.

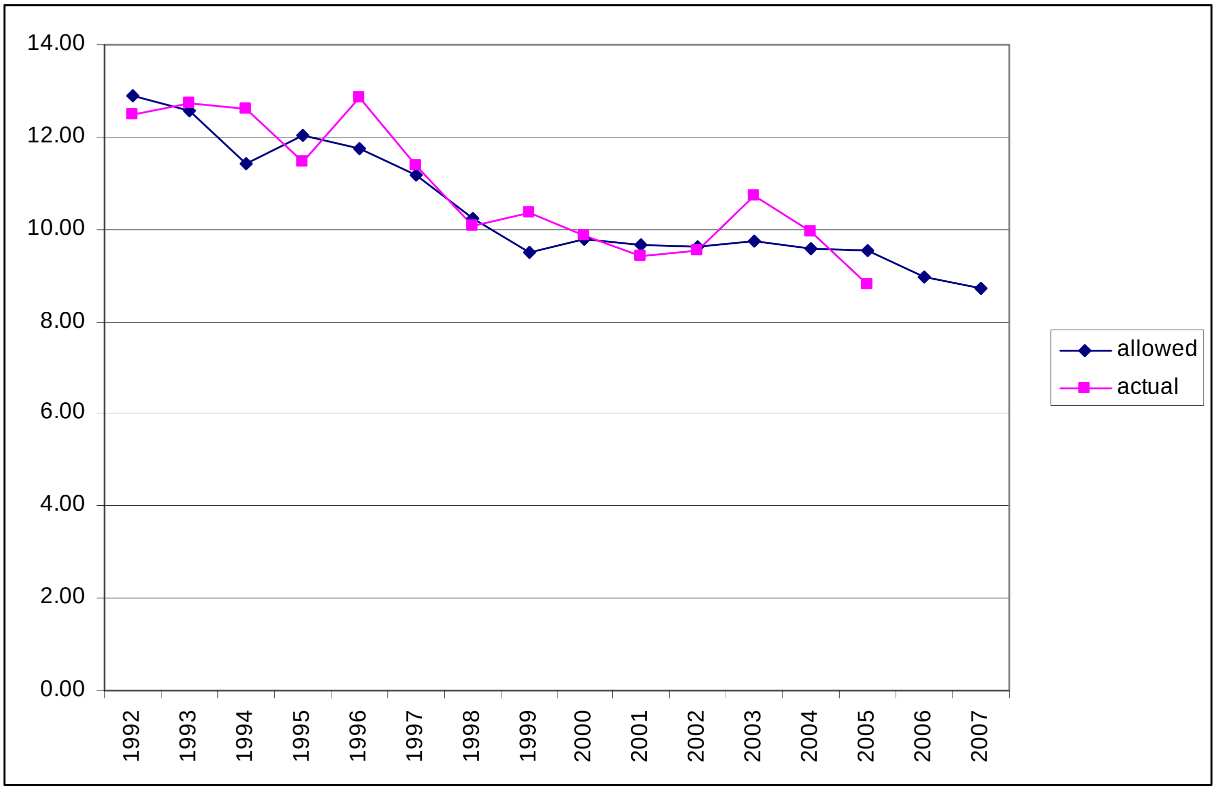
It follows that if the ratemaking mechanisms defined by regulatory legislation and rulemaking (*i.e.*, how costs are added together and then divided by measured sales to form the rate) are the same in Canada and the US, then the allowed ROEs are directly comparable. After the fact, some utilities may profit more than others (*e.g.*, those in fast-growing service territories versus slow-growing ones).[9] Or there may be some times when it is easier than others for utilities to profit (*i.e.*, when capital costs are generally falling rather than rising against a fixed set of just and reasonable rates). But with the commonality of ratemaking mechanisms in Canada and the US, the role of the allowed ROE is the same. Hence, its comparability across jurisdictions is proper.

If ratemaking procedures and operating conditions are comparable in Canada and the US, there would be no reason to expect utilities in either country would regularly earn more than the allowed ROE. **Figure 2** shows that, as we would expect, given our review of the mechanisms of rate regulation in Canada, earned returns have been both above and below allowed returns in

[9] There is a comparison between returns for Canadian and US regulated pipelines, offered in NEB RH-2-2004 by CAPP (the Canadian Associate of Petroleum Producers) that might seem to suggest a persistent success in achieved returns for Canadian companies versus their US counterparts (although we have not looked closely into the sources or particular reasons for those results reported by CAPP). We note, however, that these are returns obtained by federally-regulated interstate pipeline companies, not local gas utilities. Those pipeline companies do not have the public service obligations or stable customer base of distribution companies, and they are not informative to the comparison of the Canadian versus US *utility* ROEs. *See:* NEB, *Reasons for Decision* RH-2-2004 Phase II (2005), Figure 5-1.

Canada since the inception of the formula. In our experience, this pattern of allowed versus actual ROEs, reflecting occasional average divergences, is characteristic of utilities in the US as well.

Figure 2: Allowed versus Earned Returns For Gas Distributors in Canada, 1992-2007



Source: Canadian Gas Association

We show **Figure 2** merely as a way of dealing again with the statement that earned returns—an *ex post* measure of utility performance against a fixed set of "just and reasonable rates"—is not exceptional in Canada. There is nothing, to us, in **Figure 2** that removes the reasonable use of **Figure 1** as a reason to question whether Canadian ROE methods lately have been causing a divergence in the fair return between Canada and the US.

2. Capital Flows

There is no doubt that Canada and the US can experience unique macroeconomic conditions (interest rates, inflation, GDP growth, etc.). That said, Canada and the US share the longest, largest and most open trade border in the world. There has not been a shot fired in anger across this border since 1812. Canada-US trade is open, with few import or export taxes or tariffs.

Energy trade in North America is governed by the North American Free Trade Agreement (NAFTA), the Canada-US Free Trade Agreement (FTA), and the General Agreement on Tariffs and Trade (GATT). Among other things, NAFTA has "provided the building block for the emergence of a cooperative North American market for energy goods."[10]

Today, there are:

- 35 cross-border natural gas pipelines between the US, Canada, and Mexico.
- 22 cross-border oil and petroleum product pipelines.
- 51 cross-border electric transmission lines.

These facilities physically bind Canada and the US together.[11] This physical integration is matched by capital market integration as well. Since deregulation of the wellhead price of natural gas (1985 in Canada, 1981 in US), trade in this "increasingly significant sector" would be based on "internationally-recognized, non-discriminatory market access principles."[12] With competitive markets for the gas commodity and for transport capacity, shippers can negotiate for gas supplies and pipeline space on transmission systems in both Canada and the US, searching for the most economical mix of commodity and transport costs. The situation between Canada and the US is remarkable—unlike many parts of the world, where pipelines are not built if it means passing through other countries.

There does appear to be a preference for domestic investment, especially by pension funds and other "trustee investments," which could result in segmented capital markets. However, many Canadian firms are cross-listed on US exchanges—including Enbridge. As identified by the Concentric report, US investors do play a significant, albeit less prominent, role in the capitalization of Canadian utilities.[13] To the extent that the trustee investments in Canadian utilities represent a structural barrier to investing outside the country, then the cross-border equity investments from the US are a marginal source of funds.[14] Furthermore, some Canadian utilities and their parent companies engage in business in the US and abroad, indicating that utility companies are not regionalized.

One test of the comparability of allowed utility returns is the cost of capital for non-utility firms in Canada and the US. It may be that there are structural differences in the cost of capital

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[10] *See:* North American Energy Working Group, "North American Natural Gas Vision," Experts Group on Natural Gas Trade and Interconnections, January 2005: http://www2.nrcan.gc.ca/es/es/naewg/NANaturalGasVision_e.cfm (Accessed on October 28, 2007).

[11] *Id.*, p. 34.

[12] *Id.*, p. 10.

[13] Concentric, s*upra* note 4 p. 50.

[14] Under the efficient markets hypothesis, the marginal investor sets the price for a security. To the extent that this hypothesis holds, it may be that US investors are leading the valuation of Canadian firms. *See:* Ibbotson, R.G. and G.P. Brinson, *Global Investing: The Professional's Guide to the World Capital Markets*, McGraw-Hill: New York (1993), p. 37-41.

between Canada and the US that would result in a categorically lower cost of capital for Canadian firms, reflecting a lower opportunity cost of investment for Canadian utilities.

In an attempt to address this question, a 2007 study by researchers at the Bank of Canada estimated a cost of capital 30-50 basis points *higher* for Canadian firms than US firms, all else equal. The study estimated cost of capital based on a forward-looking, discounted cash flow (DCF) analysis of Canadian and US firms from 1988 to 2006.[15] This study takes into account forward-looking investor expectations, and is evidence that the cost of capital does not appear to be categorically lower in Canada.

3. Tax Differences

Differences in tax laws have been proposed in some previous discussions about the differences in recent Canadian and US allowed returns as a potentially confounding factor in Canada-US comparisons. Tax rates facing Canadian and US investors are indeed different, both for domestic and cross-border investments. However, it is the practice of Canadian and US regulators to set allowed ROEs on a pre-tax basis, permitting income taxes for the utility, as such, to enter the ratemaking formula as a pass through expense in permitted rates.[16] In other words, income taxes are treated in both jurisdictions as a measurable expense when grossing up the pre-income-tax ROE to calculate a post-income-tax figure for use in setting consumers charges. Therefore, as the income tax treatment is similar, if the institutional, financial and economic risk environments are comparable, ROEs are comparable as well, regardless of differences in taxation.

4. Macroeconomic Interest Rates

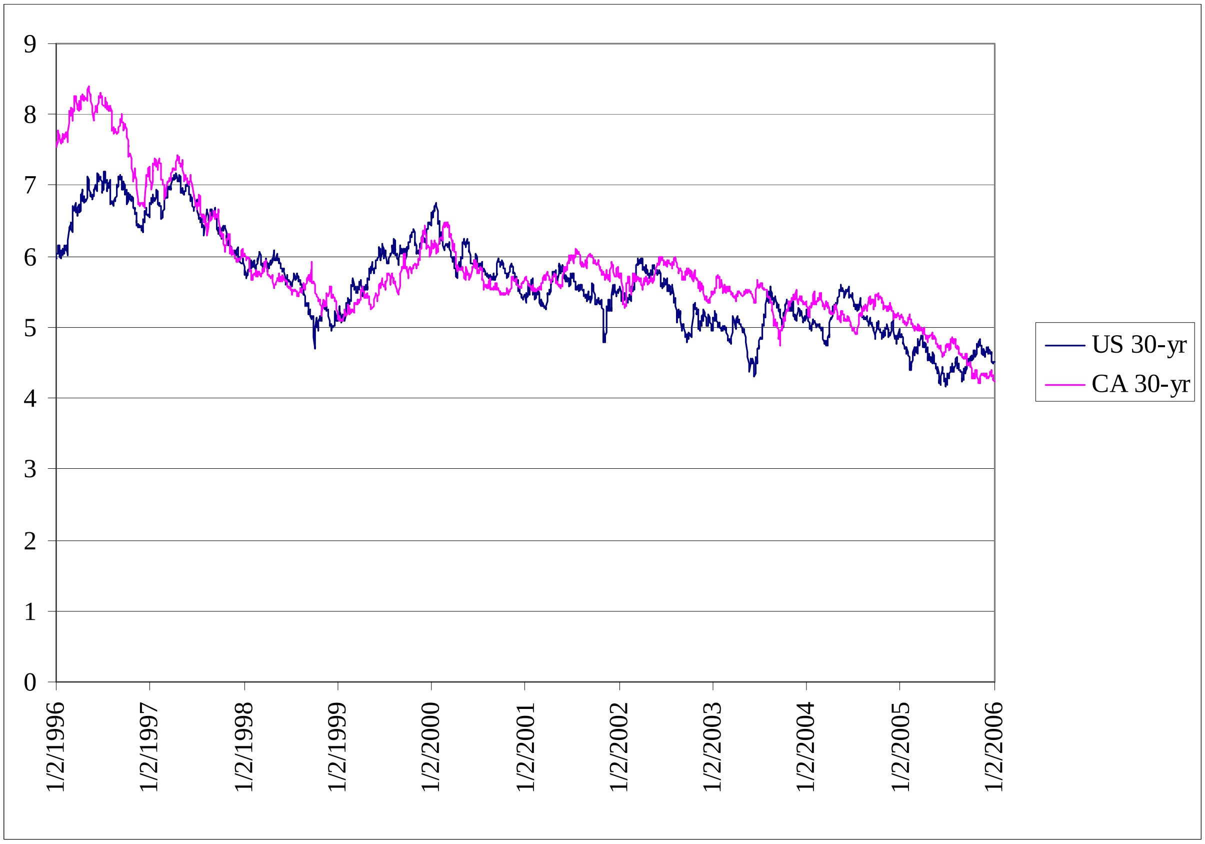
If interest rates forecasts are substantially lower in Canada, the apparent disparity in allowed returns may simply be a byproduct of lower underlying capital cost rates, and there may be no difference in the relevant fair ROE awarded by Canadian and US regulators.

As **Figure 3** shows, interest rates have been in rough parity since the beginning of the divergence, and US long-bond yields were even below Canada's for much of the time. This would indicate that macroeconomic interest rates are not driving the divergence since 1998 (although they may account for some of the positive divergence before that time), given that US interest rates have been both above and below Canada's rates during the period of interest.

[15] Witmer, J. and Zorn, L. "Estimating and Comparing the Implied Cost of Equity for Canadian and U.S. Firms" Bank of Canada Working Paper 2007-48 (2007). Available at: http://www.bank-banque-canada.ca/en/res/wp/2007/wp07-48.pdf (Accessed on 11/15/07).

[16] The income taxes on dividends or capital gains for individual investors are not a subject of concern to Canadian or US regulators—only the income taxes that form a part of compensatory rates for the utility.

Figure 3: Long-Term Bond Yields in Canada and the United States (1996-2006)



Source: US Treasury Department and Bloomberg

C. The Source and Form of the New Canadian ROE Methods

Beginning in 1994, Canadian regulators—first some, then others—have adopted automatic adjustment mechanisms for setting the ROE in utility rates based on a fixed spread with observed movements in Canadian interest rates on long bonds. In these jurisdictions, the ROE is automatically adjusted annually based on movements in long-term bond forecasts.

The approach used by the NEB, Ontario, Quebec and Alberta is to establish a "benchmark" ROE that is applied to all utilities, with individual business risks taken into account when the capital structure is "deemed."[17] The generic ROE is then adjusted annually as follows:

[17] Capital structures are "deemed" in Canada based on relative business risk. An LDC with more business risk will be deemed a higher equity ratio in its capital structure to raise the overall weighted average cost of capital. This contrasts with the US, where LDCs are predominantly allowed to choose their capital structure within a band of reasonableness.]

1. The forecast yields on 3 and 12 month out 10-year Canadian bonds are obtained from the most recent forecast by Consensus Economics.

2. These two forecasts are then averaged.

3. To get an estimate for a 30-year forecast, the result is adjusted to reflect the actual spread between 10-year and 30-year bonds in the previous month as reported in *The Financial Post*.

4. This estimated 30-year forecast is subtracted from the previous years' forecast.

5. The difference is multiplied by 0.75.

6. The new ROE is previous years' ROE plus (minus) the result.

Some provinces may use a slightly different adjustment, but the process is largely similar. The ROE adjustment is shown in Equation 1.

$$ROE_t = ROE_{t-1} + .75(Forecast_t - Forecast_{t-1}) \quad \textbf{(1)}$$

Using this formula, the following rates would result from a benchmark ROE of 12 percent based on interest rates of 8 percent if interest rates were to fall.

Table 2: Hypothetical Formula-Based ROEs

Bond forecast	Allowed ROE
8.00	12.00
7.00	11.25
6.00	10.50
5.00	9.75
4.00	9.00
3.00	8.25

The formula approach was first introduced in British Columbia in 1994 before being adopted by Manitoba and the NEB in 1995. Ontario adopted the NEB approach for 1997, and was followed by Quebec in 1999. Finally, Alberta adopted formula adjustments in 2004.

Table 3: Major Jurisdictions Implementing Formula-Based ROEs

Regulator	Jurisdiction	Case ID	Year
British Columbia Utility Commission (BCUC)	British Columbia	Decision in the Matter of Return on Common Equity, June 10, 1994	1994
National Energy Board (NEB)	Federal	Reasons for Decision re: RH2-94 Cost of Capital, March 1995	1995
Public Utilities Board of Manitoba (PUBM)	Manitoba	PUB Order 49/95	1995
Ontario Energy Board (OEB)	Ontario	Draft Guidelines on a Forumla-Based Retun on Common Equity for Regulated Companies	1997
Regie de l'Energie	Quebec	D-99-11	1999
Alberta Energy Utilities Board (EUB)	Alberta	2004-052	2004

The 0.75 adjustment factor arose out of the 1995 NEB formula decision. The formula is based on the historical observation that allowed returns tend to move in the same direction as long-term bond yields. There was a desire to protect utility customers from high bond yields and shareholders from low bond yields, so the NEB decided to weight the ROE movement by 0.75 times the change in bond prices. Previously, Manitoba had used a 0.8 adjustment, while British Columbia made one-to-one adjustments if bond prices moved outside of a certain band.

Before the formula can be applied, a base ROE must be calculated. The benchmark ROE may be arrived at in a variety of ways, and is set in a manner similar to the setting of ROEs in the US. Equity risk premium (ERP) analysis, capital asset pricing model (CAPM) analysis and, less often, comparable earning analysis are all taken into consideration. Notably, the DCF method is given little to no weight, for a variety of reasons. For example, the NEB has acknowledged that the DCF test is theoretically sound, but raised concerns about practical difficulties.[18]

Not all major Canadian jurisdictions had implemented formula-based ROEs when US and Canadian returns began to diverge. However, the jurisdictions retaining case-by-case analyses seemed to set ROEs in a manner that was highly sensitive to changes in the bond markets.[19] One could therefore view the “formula” jurisdictions as price leaders who set the standard for following the decline in bond prices in the setting of returns.

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[18] NEB, Reasons for Decision RH-2-94 (1994) §2.5.

[19] See, Alberta Energy and Utilities Board (EUB), *Canadian Western Natural Gas Co. Ltd. 1997 Return on Common Equity and Capital Strucutre and 1998 General Rate Application*, Decision 2000-9 (2000). On page 65, the EUB states, “[t]he Board notes that interest rates and bond yields have significantly declined during the time frame… Consequently, this significant reduction in interest rates will have a major impact on the determination of a fair return for a utility.”

The unique feature of the Canadian ROE formula is that is sets a gap between Canadian long bonds and the fair ROE, as shown in **Figure** 3. The only reason that the ROE does not move in lock step with the long bond is the *notion* that the spread grows/shrinks with the move in the bond, by a quarter of the bond's movement. We say "notion" purposely, because the formula's tie between long bonds and ROE is not based on financial evidence on the contemporaneous spread between what the market requires as a return on bonds as opposed to a return on equity investments in Canadian utilities.

This last point bears emphasis. For those jurisdictions that have adopted the formula shown in Equation 1, or those jurisdictions led by those who do, the only new evidence determining ROE in utility rate cases is the movement in long-bond interest rates. Nothing in the application of the formula, as a factual matter, attempts to gauge contemporaneous equity cost rates. Rather, the formula adjusts ROEs based on the historical observation that allowed ROEs move in the same direction as bond yields.

In this fashion, the Canadian formula diverges from attempts in the US to streamline cost of capital proceedings by implementing a generic formula for the cost of capital. There have been two highly visible attempts to do such a thing in the US, by the Federal Energy Regulatory Commission (FERC) in the late 1980s and by the New York Public Service Commission (NYPSC) in the early 1990s.[20] In both of those cases, the target of the generic formulae was the cost of equity, using contemporaneous market information with theoretical models designed specifically to gauge equity costs.

Neither the FERC nor the NYPSC methods ultimately resulted in an abandonment of a case-by-case examination of the cost of equity. The FERC methods have streamlined somewhat the construction of the "proxy groups" for gathering market information on similarly-situated regulated firms and have basically set the form of the theoretical formula for combining stock yields plus analyst growth rates (in the "yield plus growth" or DCF formula). Those streamlines aside, the FERC generally dropped its pursuit of a generic formula by about 1992 over legal concerns that a company-specific record must support the finding of a fair return. The FERC since has not departed from a case-by-case examination of the cost of equity. The NYPSC formula, for its part, was created after a multi-month process costing some millions of dollars. It, too, centered on a formula for deriving the cost of equity (rather than the long bond rates plus a pre-determined spread), but it was never adopted formally by the NYPSC.

IV. THE TRADITIONAL CASE-BY-CASE METHODS OF CANADIAN AND US REGULATORS

Rate cases in the US are relatively standardized affairs. This is not to say that US commissions never err in their decisions, that all commission decisions are objective or that rate cases are

[20] FERC Order 442 *Generic Determination of Rate of Return for Public Utilities*, Docket No. RM85-19-000; New York Public Service Commission, *Generic Financing Proceeding, Case* No. 91-M-0509.

never protracted battles. Property rights and US regulation are continually evolving and have only reached their current state through experimentation and judicial rebuke.

In an attempt to relieve the regulatory burden the FERC intended to move to a generic ROE approach in the 1980s with Orders 420, 442 and 461, and similar efforts were made by the NYPSC and the Federal Communications Commission (FCC) in telecommunications. However, the generic ROE pursued in these cases was never applied extensively and fell into disuse. US ROEs are now determined the same way they have always been determined: through discounted cash flow (DFC) analysis that examines a comparable group similar to the utility in question.

US gas utilities generally do not generally undergo annual rate cases.[21] Rather, the ROE stands until either the utility requests a rate case or the commission judges that conditions have changed enough to warrant a re-examination of rates. To streamline rate cases, commissions have objectivity standards that include the need for a theoretical justification of the methods used and all subjective decisions are justified in the public record. These standards help to ease contention in rate cases and limit the discussion to manageable issues.

In this section we will explore the methods used for rate setting in a case-by-case environment. We begin with the most popular method in the US, the DCF, before examining the CAPM and other ERP methods. Finally, we discuss the role of capital structures in case-by-case ratemaking.

A. Discounted Cash Flow (DCF) or "Yield Plus Growth"

The most popular method used to determine the ROE among US regulatory commissions is to determine what future stream of common dividends investors expect on a case-by-case basis using discounted cash-flow (DCF) analysis. Its popularity is a function of its ease of use and comprehension by finders of fact not necessarily particularly versed in financial theories. At its most fundamental level, the DCF method endeavors to compute the cost of equity capital by summing the two sources of equity investor returns—the "yield" portion (meaning the dividend yield with respect to the stock price) and the "growth" portions—the rise in the stock price that investors expect to see. In a world of complicated ratemaking formulae and financial theories, it is no surprise that "yield plus growth" has an intrinsic appeal, particularly when there are many sorts of similar utilities by which to gauge the sum of these two common-sense factors that make up the ROE. The formal statement of the DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[22]

Part of the DCF formula that may not appeal to analysts and regulators is the growth rate expected by investors. That growth rate is inherently inscrutable, and in small capital markets

[21] California has annual adjustments to rates, but that is a unique US jurisdiction and not in any way an indicator of what happens in the rest of the country. The tortured experience associated with the lead up and aftermath of the California energy crisis of 2000-2001 continues to cast regulatory procedures there in a unique light.

[22] *See* Gordon, M.J. *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

(such as many utility jurisdictions overseas), it is very hard to gauge investor expectations and thus to apply the DCF model. But in the US, where the model retains its great popularity, a robust industry of independent stock market analysts helps greatly. Both in print and on the web, disinterested estimates of utility growth rates are readily available to assist in the calculation of DCF-derived ROE figures. Combining these publicly-available growth rate estimates with the availability of a number of similar-risk companies, in "proxy groups," allows regulators to enjoy the stabilizing influence of the law of large numbers in setting the ROE.[23] For practical-minded regulators looking for stable, understandable and objective evidence, its popularity is no surprise.

DCF analysis involves making selections at two key stages: first, the analyst selects a specific "proxy group" of utilities facing similar risks and then selects the various of inputs such as the growth rate. Many of the practical concerns of Canadian regulators over these selections have been addressed in US jurisdictions, and the regulatory burden of case-by-case ratemaking has been lightened by establishing consistent selection criteria at each stage. One concern unique to Canadian jurisdictions, however, is the applicability of proxy groups that contain US utilities.

Given the degree of capital market integration, the degree of cross-border gas trade, and the international presence of several Canadian LDCs, we believe that a proxy group that includes US utilities facing similar risks would be appropriate for Canadian utilities. We will examine in Section IV whether the risks facing Canadian utilities are, in fact, comparable to those facing US utilities but, so long as Canadian regulators are attentive to potential macroeconomic divergence, we see no economic or financial factor that would confound the use of proxy groups that include US utilities.

B. Equity Risk Premium (ERP) and the Capital Asset Pricing Model (CAPM)

Equity risk premium (ERP) analysis is based on the observation that it is more risky to hold equity than bonds. Assuming that investors are risk adverse, they will require a higher return to hold assets with higher risk. Equity returns therefore carry a premium over bond returns. If risk-free bond yields could be identified and the equity premium could be estimated, the cost of capital will result.

There are a wide variety of methods for estimating the cost of capital along these lines, the most popular of which is the capital asset pricing model (CAPM). The CAPM formula itself is rather straightforward. Its components are: (1) the risk free rate of return; (2) the market rate of return; and (3) the beta. These inputs are combined to estimate the ROE.

[23] In practical terms, the "law" describes the stability of a random variable, with repeated sampling. That is, given a sample of independent and identically distributed random variables, the sample average will approach and stay close to the true population average as the size of the sample increases. This is a long way of saying that the ROE results from a "proxy group" sample of similar utilities are more representative of the actual ROE than the ROE for a single company alone.

$$ROE = \text{Risk-Free Rate} + \beta(\text{Market Return}) \quad \textbf{(2)}$$

Despite this algebraic simplicity, there are different methods to obtain each of these components and to compute the required rate of return. The effects of choosing one method over another can substantially change the required cost of capital. Because CAPM, with the exception of the beta term, does not have the "law of large numbers" properties in a comparable group that the DCF has, there is less reason to focus primarily on a comparable group rather than the utility in question, especially when the beta is significantly different from that of the proxy group.

The practical elements of the CAPM formula are full of contention. For example, the beta term relates the movement in an individual company stock price compared with that of the entire market for stocks. Greater relative movement vis-à-vis the market means a higher beta. Those betas published by investment analyst houses (such as *Value Line*, Merrill Lynch or others) make use of an adjustment procedure that moves "raw" betas toward 1.0. The "adjusted" published betas are generally the ones used by US regulators when they make reference to the CAPM.

The other area of contention is the market return—defined as the premium that the market for equities demands as a spread on the risk free rate. Market risk premiums are not published, but have to be derived. Some are based on historical achieved returns and others try to gauge investor expectations on future equity returns not unlike those who perform a DCF analysis. In rate case application of the CAPM, there is always dissension among interested parties regarding the size of the market risk premium, as its choice directly affects the level of "just and reasonable" rates. Practical-minded regulators wrestle with this issue.

- Despite these areas of contention, one benefit of the use of the CAPM is that the theory upon which it rests provides a relatively clear method for gauging the effect of increased leverage, or "gearing," on the cost of equity. It is well known in both financial theory and in practical investment circles that a high proportion of debt in the capital structure adds financial risk to the business risk facing a company—and raises both the cost of debt and equity. The CAPM model provides a theoretical method to compute the effect of different gearing on the ROE.[24] Indeed, in some prominent cases in the US, the this method has been used as the basis for regulators to grant higher equity costs to adjust for the use of greater gearing levels as deemed prudent by the regulator.[25]

[24] For the theoretical formula regarding the relationship between betas (and hence equity costs) and gearing, see: Copeland, T.E., and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*, Addison-Wesley, Reading, Massachusetts (1988), p. 457.

[25] For example, in the aftermath of the electricity utility restructuring in Texas, the Public Utility Commission there approved a 50 basis point "financial risk" premium to the cost of equity for all electricity distributors in the state to reflect its desire that the utilities all move toward a higher amount of debt in their capital structures (60 percent) reflecting the spin-off of their generating function. *See* Public Utility Commission of Texas, *Order No. 42: Intermin Order Establishing Return on Equity and Capital Structure*, Docket No. 22344 (2000).

CAPM is often used in US rate cases, but it is almost never used as the sole determinant of the cost of equity capital.[26] The judgment required in selecting parameters for the CAPM is no less significant than the judgment required for judicial use of the DCF, and the CAPM lacks the "central tendency" properties of DCF that smooth the results to yield a more reliable estimate.

C. Capital Structure

Modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[27] In the US, a utility's management is therefore granted a measure of discretion as to the type of capital raised. Having a solid level of financial integrity can provide rate stability and other benefits to customers, and commissions are reluctant to interfere with a utility's capital structure unless it is pushing the bounds of reasonableness.

In the US, the projected actual capital structure ratios of the utility at the time that new rates would go into effect are used to calculate a pre-tax weighted-average cost of capital. Because the rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components on the best available estimates for the period of time in which the rates will be in effect. Furthermore, the actual degree of leverage has important implications for ratemaking, as higher leverage raises financial risk and therefore the cost of capital.

Financial risk is the portion of total corporate risk over and above basic business risk that results from using debt.[28] Because equity investors are the residual claimants after the payment of debt, the cost of equity increases with higher debt ratios (*i.e.* with higher leverage). As a company increases the portion of debt in its capital structure, investors perceive a greater chance that there will not be sufficient returns available after the payment of fixed charges. Both the Modigliani-Miller theory, a the basis for the field of finance, and empirical tests of the theory confirm this inextricable link between capital structure and the cost of equity.[29]

The total cost of capital is therefore U-shaped with respect to capital structure. High equity percentages raise the WACC, but the WACC also increases at high debt percentages as investors seek higher returns on equity due to the increased financial risk.

[26] One jurisdiction in our experience, Oregon, for some time in the 1990s and into the mid 2000s appeared to use the CAPM as the sole method for finding the ROE. It stopped that seemingly sole reliance in 2001. *See* Public Utilities Commission of Oregon, Order No. 01-777 (2001).

[27] *See* Morin, R., *Utilities' Cost of Capital*, PUR, Arlington, VA 1984, p. 268.

[28] Brigham, E.E., *Financial Management, Theory and Practice, Third Edition*., The Dryden Press, Chicago (1982), p. 861.

[29] *See* Copeland, T.E. and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*., Addison-Wesley, Reading MA (1988), Chapters 13 (theory) and 14 (empirical evidence and applications).

Hypothetical capital structures have been used in the US when it was judged that utilities were deviating from reasonable capital structures by either employing too much debt or equity in an effort to raise overall returns. Hypothetical capital structures may also be used if the utility is owned by a parent company that faces markedly difference risks from those faced by utilities and therefore carries a capital structure that would be inappropriate for a utility.

In such cases, the capital structure of a comparable group of utilities is used, on the basis that comparable groups' capital structures reflect the opportunity costs facing investors, satisfying the comparable investment standard. Very rarely would a capital structure be "deemed" in the US without consulting a comparable group and addressing why the actual capital structure chosen by the management is inappropriate.

V. RELATIVE RISK FOR CANADIAN AND US GAS UTILITIES

The previous two sections of this paper described how Canadian and US regulators have derived the ROE. This section investigates whether there is any justification for concluding that lower (higher) risks for utilities in Canada (the US) justify ten years of divergent returns.

In this section, then, we first examine more carefully which risks matter to utility investors. We then examine the practical boundaries to those risks for regulated utilities in Canada and the US and upon what legal and procedural foundations those risks rest. Finally, we examine whether there is any evidence available that allows us to conclude that the divergence in Table 1 stems from any persistently lower risk in Canada for gas distributors than that level we observe in the US.

A. What Risk Matters to Utility Equity Investors?

Any discussion of risk in the context of utilities invites controversy. Much of this, in our opinion, comes from a *colloquial* as opposed to a *technical* definition of risk in the context of ROE. In setting a fair compensation for investors in the ROE, the risks that matter are the ones for which those investors require compensation. Colloquially, all would agree that predicting the weather is *risky*, but to the extent that over time weather conforms tightly to averages, the rates set on average weather patterns carry no particular risk to investors' ability to recoup their cost of capital. That is to say, *weather risk* is not the same as *ROE risk*. For a natural monopoly gas utility whose costs are geared to serving customers with whatever local weather conditions exist, the weather does not stand between them and recouping their funds—and is not properly a part of the ROE.

Weather is merely one example of the need to focus on technical risk definitions in gauging the fairness of the ROE. While the cost of service may differ between US and Canadian utilities based on their distinct geographies and other factors, both can expect the opportunity to earn a fair rate of return that is based on the returns to an investment of comparable risk.

1. Regulatory Risk

The risk that a gas LDC faces is inherently intertwined with regulation. Gas LDCs are a natural monopoly—the only thing standing between an LDC and monopoly profits is regulation. The greatest risk to an LDC is the risk that the regulator will not allow the utility to recover prudent costs—including the cost of capital—in a timely manner.

2. Business Risk

The business risk faced by LDCs in Canada does not significantly differ from those in the US. There are forward-looking risks facing investors that are somewhat independent from regulatory risk. These risks are limited, however, as a utility has the right to call for a rate case if significant events (such as a recession) damage its ability to earn a reasonable return on its invested capital without an increase in prices—a recourse obviously not available to unregulated firms. Business risk is therefore an interaction between regulatory risk and the business environment and many business risks can be lessened, modified or even eliminated through various regulatory practices.

Forward-looking business risks include:

- *Long-Lived Assets*. Gas LDCs in Canada and the US connect to a multitude of consumers. Therefore, distributors are the ones charged with the planning of upgrades to networks that in many cases are decades old. The need for major expenditures to provide safe local service do not always follow rate case schedules, so there is often a lag between investments in long-lived assets and recovery of those costs in rates. Such risks in the cost of planning and engaging in ongoing local network maintenance are the same in both Canada and the US, and both utilize deferral accounts to mitigate this risk.

- *Risks of service interruptions*. Major or minor service interruptions are generally the responsibility of the distributor—as are the costs of remedying outages. Cracked gas mains, storm damage to electricity wires and sub-stations, are all the responsibility of the distributor, which can try to plan for—but cannot guarantee—the collection of all costs that are incurred.

- *Adequacy of depreciation*. The depreciation allowance included in distribution company rates is an estimate based on historic experience. Depreciation allowances may not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions. As such, there is a risk that utility plant will be under-depreciated, and changes in technology or regulation may cause shareholders to bear the result of inadequate depreciation.

- *Risk of technological bypass*. Gas LDCs in Canada and the US are at risk of customers bypassing the network by switching fuels or adopting alternate technologies. If bypass is significant there is no guarantee that the remaining rates will be adjusted to recover the cost of abandoned or excess capacity.

- *Risk of the competitiveness of rates*. While LDCs are entitled to recover their actual, prudently-incurred cost of doing business, gas LDCs in Canada and the US are at risk for the continued viability of the overall business. Competitive pressures from distributed generation or alternate fuels could create a situation in which allowed revenues are not competitively viable.

- *Risk of timeliness and adequacy of allowed revenue levels*. Gas LDCs in Canada and the US face the need to increase distribution rates as costs increase. It is expensive and difficult to file for a small rate increase. Utilities would absorb such costs until they become large enough to justify the cost of a rate filing.

3. Financial Risk

Apart from the regulatory and business environments facing an LDC, investors face financial risk as well. Financial risk is the risk associated with carrying debt in the capital structure. Debt return (i.e., interest payments) are contractual obligations. Up to a point, raising utility funds with debt provides for a less expensive way to provide the capital needed to provide services to customers. But with greater proportions of debt, the risk that those interest payments will not be "covered" increases, and with it both the interest rate demanded by lenders and the return required by equity investors. This effect on required rates of return is well established and widely known.

Financial risk is generally taken into account in setting ROEs in US rate cases. To the extent that a regulated firm's capital structure mimics those of a group of its regulated peers, no adjustment is necessary for financial risk. One the other hand, if there is a difference between the firms in question and their peers, then an adjustment to reflect the differential financial risk may be necessary (as happened in a noteworthy case for all of the regulated electric distributors in Texas—where a 50 basis point premium for the ROE was permitted to reflect the regulator's desire for the distribution-only utilities to take on more debt).[30]

The question of financial risk appears to often be obscured in Canada, where the generic ROE is provided for all utilities in a jurisdiction, leaving the issues of financial risk to be deal with in a specific deemed capital structure to address the risks of a particular distributor.

B. What are the Practical Boundaries to Regulatory Risk?

With any investor-owned utility, the regulator and the utility have reciprocal obligations that are generally well recognized. That is, the utility operates the service and provides the capital needed to maintain and expand the facilities that allow the public to be adequately served. For its part, the regulator provides a stable regulatory environment, oversees the adequacy of services, and offers the utility a reasonable opportunity to earn a return on its investments.

[30] See Texas PUC, *Generic Issues Associated with Applications for Approval of Unbundled cost of Service Rates Pursuant to PURA §39.21 and PUC Subst. Rule §25.34*4, Docket No. 22344.

Among its various duties, a key role for regulators is to signal, credibly, to investor-owned utilities' investors how their investments will be recovered in regulated charges.[31]

Such regulation is described in the economic literature as a "form of long-term contracting."[32] Canada and the US have proven over 100 years of natural gas regulatory history that they are able to honor the "long-term contract." The exact form of this long-term contracting has evolved throughout this history as regulators pushed against the regulatory boundaries, were reprimanded by courts, were given new direction through legislative action, and were chaired by individuals of various political inclinations as new executives were elected.

In mature regulatory jurisdictions with strong legal and administrative histories, such as Canada and the US, the regulatory compact represents a concatenation of: (1) strong primary legislation; (2) credible, comprehensive and transparent administrative procedures for making regulatory decisions and adjudicating disputes; (3) accounting regulation specifically designed for utility ratemaking; and (4) clear pathways for reliable judicial review of regulatory decisions. Newer regulatory jurisdictions around the world that do not have comparable bodies of regulatory precedent routinely use explicit contracts to express such principles.

1. Strong Primary Legislation

Canadian regulatory legislation is effectively very similar to that in the US, although Canada does not have all of the judicial precedent regarding the constitutional protection of private property that characterizes the US. Canada's regulatory compact is based instead on common law and "fundamental justice" but nevertheless does appear to be comparable the US in practice.[33] The US Constitution, especially the fifth and fourteenth amendments, provides the foundation that supports those protections in the US.

In Canada and the US, Supreme Court interpretations of this primary legislation define the legal limitations on regulators' ability to take action on charges that may damage the value of utility investors' property. The best known case is that of *Federal Power Commission v. Hope Natural*

[31] This mutuality of obligations is sometimes called the "regulatory bargain" or "regulatory compact," but those are merely convenient labels for how governments and investors have traditionally worked out how the public will be adequately served by private companies.

[32] Professor Oliver E. Williamson, an authority on the economics of transactions and regulation, noted that "[a]t the risk of oversimplification, regulation may be described contractually as a highly incomplete form of long-term contracting in which (1) the regulatee is assured an overall fair rate of return, in exchange for which (2) adaptations to changing circumstances are successively introduced without the costly haggling that attends such changes when parties to the contract enjoy greater autonomy." Williamson, O.E., *The Economic Institutions of Capitalism*, Free Press, New York (1985), p. 347. See also Victor Goldberg, Regulation and Administered Contracts, *Bell Journal Of Economics*, Vol. 7 (Autumn 1976): p. 426-448.

[33] Canada's equivalent to the US 14th Amendment, Section 7 of the Charter of Rights and Freedoms, states: "[e]veryone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice." As a relatively recent act, it remains to be seen exactly how "fundamental justice" will be interpreted but it has thus far been interpreted as more than simple procedural rights.

Gas, in which the Supreme Court set a standard for determining "just and reasonable" returns, a standard that has stood the test of time.[34] Canada and the US share a remarkably similar regulatory mandate and their "fair and reasonable" standards for utilities returns are almost identical. Indeed, Canada's *Northwestern Utilities v. City of Edmonton* anticipated the landmark US *Hope* case by fifteen years. Both established the opportunity cost of capital as the relevant standard by which utilities' returns should be judged.

The Supreme Court of Canada stated in *Northwestern Utilities*:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise…[35]

In the *Hope* decision, the US Supreme Court, by a vote of five to three, set a new standard for determining "just and reasonable" returns for investor-owned utilities.

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[36]

In *Bluefield*, an earlier case leading up to the *Hope* decision, the US Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties...[37]

In setting required revenues, a utility's returns would henceforth be measured by investors' possible earnings on alternative enterprises of similar risk. The Supreme Courts thus ruled that a utility's investments were safe from seizure (*i.e.*, a "taking") if regulators set charges to award returns consistent with investors' opportunity cost of

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[34] *Federal Power Commission v. Hope Natural Gas*, 320 US 591 (1944).

[35] *Northwest Utilities v. City of Edmonton*, S.C.R. 186 (NUL 1929).

[36] *Hope,* 320 US 591, 603 (1944).

[37] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 US 679, 693 (1923). The *Hope* and *Bluefield* decisions refer to two Constitutional Amendments. The Fifth Amendment, as interpreted by the Court, gave the Court jurisdiction over Congress in such matters. The Fourteenth Amendment, under the Court's interpretation, gave it similar jurisdiction over the States.

capital. These limitations on the discretion of regulators were not academic exercises. For the purposes of the future gas market, the *Hope* and *Northwest Utilities* decisions were critical. They sharply limited investor or shipper uncertainty regarding the ability of regulators to act in a manner that would damage the value of the assets that investors would devote to regulated enterprises.

2. Credible, Comprehensive and Transparent Administrative Procedures

Predictable regulatory or tariff-making practices are unlikely without a clear set of administrative procedures that bind the way that the independent regulators conduct their business. Canada and the US both provide stability to their utility investors through strong administrative procedures.

An important tenet of Canadian administrative practices is the common law right to procedural fairness. The Supreme Court of Canada has held that judicial and quasi-judicial bodies, but also other administrative decision makers, must follow common law principles of procedural fairness that include the right to be heard and the right to be judged impartially. [38]

The 1946 Administrative Procedures Act guides regulatory procedures in the US. Similar to Canada, it requires regulators to hold hearings, warn participants of impending rule changes, to allow participation in regulatory proceedings from the affected parties and to accept evidence (subject to cross-examination in those hearings). The late US Senator Daniel Patrick Moynihan explained that:

> The APA rests on a constellation of ideas: government agencies should be required to keep the public informed of their organization, procedures, and rules; the public should be able to participate in the rule-making process; uniform standards should apply to all formal rule-making and adjudicatory proceedings; and judicial review should be available in certain circumstances. Taken together with the Freedom of Information Act, an amendment to the APA that was enacted in 1966 and added to in 1974, 1986, and 1996, the APA was intended to foster more open government through various procedural requirements and thus to promote greater accountability in decision making.[39]

These are precisely the elements of “due process” in the administration of regulation. Indeed, the legal inquiries that resulted in the Administrative Procedures Act arose out of the general judicial concern (arising in the US in the 1930s) that regulating prices of investor-owned companies *at any level* represented a potentially unconstitutional taking of private property. That

[38] An important decision with regard to procedural fairness was *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, where the Supreme Court of Canada significantly extended the rights to procedural fairness to non-judicial administrative decision makers and solidified the right to justification for a decision. *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, [1979] 1 S.C.R. 311.

[39] Daniel Patrick Moynihan, *Secrecy: The American Experience* New Haven, Conn: Yale University Press, 1998, p. 157.

potential unconstitutionality, it was rightly thought, could only be prevented if a specific framework was applied for assuring the due process of regulatory decisions.

While Canada does not have an exact equivalent to the U.S. Administrative Practices Act of 1946, it does have an umbrella of provincial statutes, the charter(s) of the administrative decision maker(s), and the protection of common law, which includes previous interpretations as well as foundational justice and the founding principles of the constitution.[40] Through these channels, Canadian administrative procedures are equally well-established and effective as US procedures.

3. Accounting for Utility Ratemaking

The goals of effective and efficient regulation can be frustrated without a consistent, credible, and sustainable set of regulatory accounts. Strict accounting standards (*i.e*., the Uniform System of Accounts) rarely leave US or Canadian energy utilities and their regulators in major dispute over basic financial issues (like profitability, depreciation expenses or the admissibility of particular costs).

Strong and transparent accounting standards were established over half a century ago in Canada and the US, but such is not the case in other, supposedly "mature" jurisdictions. For example, a major component of the reviews of British Gas conducted in recent years by both Ofgas (the gas regulatory body before Ofgem was created) and the Monopolies and Mergers Commission concerned basic accounting and finance items in an environment with no regulatory accounting standards.[41] This confusion in the UK over British Gas's rate of profits on its capital stock and the depreciation allowed on billions of pounds sterling of transportation assets represents a major risk to utility investors that is absent in Canada and the US. Canadian and US accounting standards would never leave major assets in question, as was the case in the UK and elsewhere following privatization.

4. Reliable Judicial Review

Effective limits on regulatory authority in systems with well functioning regimes come from the judiciary and other paths of appeal. In both Canada and the US, the fundamental legal limitations on the ability of regulators to take actions that damage the holdings of utility investors (in some way or another) come from well-known Supreme Court decisions. The Courts in both countries have found that the property rights of investors in regulated companies,

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[40] The provincial administrative practices acts include: *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22 (Ont.); *Administrative Procedures Act*, R.S.A. 2000, c. A-3 (Alta.); *Administrative justice, An Act respecting*, R.S.Q. c. J-3 (QC).

[41] *The Economist* has referred to UK regulatory accounting as a "fiddly bit of guesswork." (See: "Don't you just love being in control?" *The Economist*, May 18th, 1996.)

as well as the rights of the customers they serve, require strict regulatory attention to invested capital.

C. What are the Elements of Canadian vs. US Regulatory Risk?

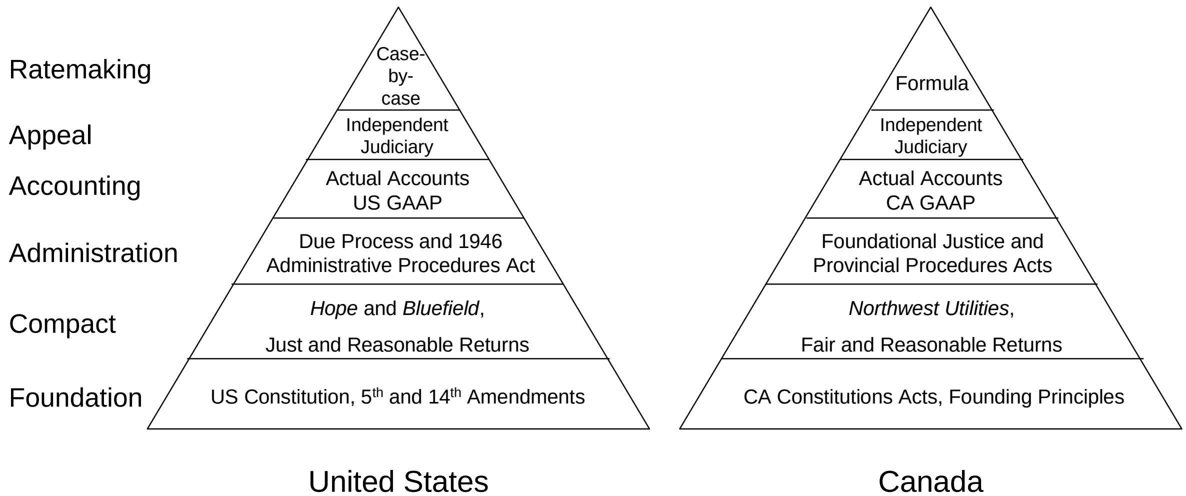
While Canada and the US share a credible regulatory environment, the exact regulatory foundations are admittedly not identical. However, the differences that do exist are more procedural than fundamental. The two jurisdictions engage in roughly the same practices, although they may go by slightly different names or receive more or less attention. The differing levels of attention does not imply that some practices are superior to others; rather, these differences arise from the dates the practices were implemented, the procedures used to handle the practices, and the emphasis placed on various practices in regulatory proceedings.

These principles are generally true of all regulatory jurisdictions in the US and Canada. Both equity investors and lenders generally give funds to utilities with the reasonable expectation the principles of obligations to be provided with a fair return will be honored. Even though the particular utility statutes may vary from jurisdiction to jurisdiction, and even though regulatory commissions may have different policies and precedents in different jurisdictions, investors anticipate the basic bargain between them and their regulator (who represents the public) will apply to their investments.

From the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the US have virtually indistinguishable regulatory environments—so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[42] **Figure 4** illustrates the regulatory pyramid in Canada and the United states.

[42] See, for example, Alberta's *Generic Cost of Capital* decision, where the EUB stated, "[t]he Board concurs that the above decisions [*Northwestern*, *Hope*, and *Bluefield*] are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities." Alberta Energy and Utilities Board, *Generic Cost of Capital* Decision 2004-052 (2005), p. 13.

Figure 4: Elements of Recent ROE Regulation in the US and Canada



Regulation in Canada and the US is founded on strong primary legislation that protects the rights of citizens. The constitution of Canada is an amalgam of codified acts and uncodified traditions and conventions.[43] The Constitutions Act, 1982 established a Charter of Rights and Freedoms, the Canadian equivalent to the US Bill of Rights. While the Charter extends many protections to Canadian citizens, including the right to "foundational justice," this Charter does not explicitly include the protection of property rights. A significant difference in the regulatory foundations is the strong constitutional protection of property rights in the United States afforded by the 5th and 14th amendments.

The regulatory compact in both countries is shaped by judicial decisions and includes the right to earn a "fair return" on investment, as determined by the opportunity cost of capital, which is termed the "comparable investment" standard. While the phrase, "regulatory compact," is not used as often in Canada as in the US, the concept is there. Indeed, the decisions that shape the US compact are cited in Canadian rate cases, and the Canadian decisions are widely recognized as establishing an effective compact that is very nearly identical to that of the US.[44]

While Canada does not have a single, federal administrative practices statue, administrative practices are highly refined in Canada and afford at least as much protection to investors as does the United States. The Canadian common law protection—enhanced by the introduction of foundation justice in the Charter of Rights and Freedoms and provincial administrative

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[43] The Preamble to the Constitution Act, 1867 states that the provinces shall have, "a Constitution similar in Principle to that of the United Kingdom."[43] This has been interpreted as stating that the practices of the United Kingdom that were common before the creation of the constitution form part of the Canadian constitution—for example, the practice of an independent judiciary has been constitutionally guaranteed under this argument. See *Provincial Judges Reference* [1997] 3 S.C.R. 3.

[44] Morin, R.A. *New Regulatory Finance*, Vienna, Virginia: Public Utilities Reports (2006), p. 12.

procedures acts—equals the US standard of due process and the Administrative Procedures Act of 1946 in its protection of investors' rights.

In both Canada and the US, regulatory accounting is sufficiently refined that actual accounts are used for ratemaking without contention, avoiding the regulatory conflicts that surround benchmarked costs or replacement value accounting. The right to use actual costs for intraprovincial/intrastate regulation comes from provincial and state statutes. While some provinces have "fair value" mandates and are not required to use book values, they do so nonetheless.[45] This is similar to the US, where five states have "fair value" statues but have defined fair value to be the book value, so it is a difference without a distinction.

There is a perception that Canadian judiciaries are reluctant to interfere with the decisions of utility regulators. However, US judiciaries also do not overturn regulatory decisions without a clear reason to do so, and judicial rebuke is the exception rather than the rule in the US. Most important is that clear pathways for appeal exist in both countries and appeals are conducted in a manner such that, should major grievances be raised, the judiciaries are capable of reaching a reasonable decision.

Canada and the US share similarly mature regulatory compacts, supported by well-established accounting, administrative and appellate procedures. They are unique in their advanced regulatory environment based on credible, actual accounts. The greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the US.

D. Does the Continued Ability to Raise Capital for Canadian Utilities Indicate that All is Well?

Figure 1 drove this examination of the foundations of the regulatory procedures and risk. It shows that the allowed ROE was persistently lower in Canada that in the US over the previous decade. To the extent that this divergence is found not to be the result of different Canadian regulatory practices or lower regulatory risk vis-à-vis the US, but the result of the use of Canada's formula, an obvious question arises: would this cause investors to withhold funds from Canadian utilities?

In other words, is there any evidence that the Canadian utilities whose returns make up **Figure 1** have been unable to raise funds? If the generic Canadian ROE formula rests too heavily on long bonds and ignores genuine equity capital costs, the most manifest evidence that this is detrimental would show up in a difficulty for those companies in raising new capital. Conversely, does the continued ability of these Canadian utilities to provide adequate services in and of itself refute any possibility that the formula-based ROE is biased or inadequate?

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[45] The use of actual accounts in Canada was upheld in *B.C. Electric Co.*, where the court established that the book value of prudently incurred costs could be used to provide a fair return, despite a statute requiring that appraisal value be used. *B.C. Electric Co. Ltd. v. Public Utilities Commission et al*. (1957) 13 D.L.R. (2d) 589 (BCCA).

We conclude that as a practical matter the answers to these questions are no. Absence of evidence that Canadian utilities subject to the formula are barred from the market for funds does not constitute evidence that those ROEs are adequate in the market.

There are times in the not-so-recent past when persistently inadequate returns have appeared for utilities in general. During two periods of high inflation in the 1970s and 1980s, US utilities faced wholly inadequate returns. Inflation, coupled with the need to construct new generation and transmission capacity, ruined the ability of traditional regulatory procedures to provide utilities with a reasonable prospect of earning an adequate ROE. In short, the traditional methods of regulating rates, using a test year, created a lag in the ability to recoup ongoing, inflated, costs that visibly affected the financial health of utilities.

Evidence that the utilities were suffering was clear in the stock markets, as utility stocks slid in relation to their book values. During both periods, it was common for utility stocks to be trading below the equity book value of utility investments (roughly the equity “rate base”). When this happened, any new equity raised by these utilities would “dilute” the equity of existing shareholders—basically providing a subsidy to new equity investors from old ones.[46] Such a subsidy could not continue forever, as it would doom an investor enterprise. As it happened, however, the problem—as highly visible as it was—was only relatively temporary.

No equity investors would willingly sell proportional rights to the future returns on the equity rate base for a discount—but they did so during this period anyway. Why? Given their overriding obligations to provide safe, adequate and reliable service to customers, they had effectively no choice in the matter. Inflation pushed up the cost of new funds to the extent that it reflected a subsidy from existing shareholders, but nothing during the years of high inflation left utilities off the hook regarding their own responsibilities to serve the public.

Fixing the problem required either a change in regulatory procedures to deal with high inflation (for example, using inflation accounting like in European or Latin American countries), or an end to high inflation itself. When inflation dropped in the US, utilities returned to business-as-usual. The prospect of high inflation is still a risk to which utilities have generally no defense except a strong belief that the central bank will work to prevent its recurrence.[47] But in no fashion was the continued investment in US utility infrastructures in the 1970s and 1980s evidence that the ratemaking formula wasn’t damaging investor interests in periods of high inflation.

Similarly, the evidence that Canadian investors continue to provide safe, adequate and reliable service to their consumers cannot be taken as evidence, in and of itself, that the formula-based returns reflected in **Figure 1** are fair. The utilities in Canada are a mixture of closely-held subsidiaries (without traded stocks of their own) and publicly-traded firms. If the ROEs based

[46] See: Morin, R.A., *New Regulatory Finance*, Public Utilities Reports, Inc., Vienna, Virginia (2006), p. 364; and Hymay, L.S., *Americas Electric Utilities: Past, Present and Future*, Public Utilities Reports, Arlington, Virginia (1985), p. 262.

[47] Of course, bankruptcy is a defense against persistent confiscatory regulatory treatment, but that has only appeared rarely in the US, and then only in conjunction with other idiosyncratic events.

on the formula are unfair, it would be, in our opinion, beyond practical measures to try to discern objectively, as a separate matter, how it damaged the interest of investors. By its very nature the market's cost of equity is not easily and objectively measurable—which is precisely why regulators and analysis use indirect formulae like the DCF and CAPM. Reverse-engineering the effect of the Canadian generic formula is not a practical and objective possibility to measure the effect it has had on utility equity investments in Canada since around 1998.

IN THE MATTER OF

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.
TERASEN GAS (WHISTLER) INC.

AND

RETURN ON EQUITY AND CAPITAL STRUCTURE

DECISION

December 16, 2009

BEFORE:

Anthony J. Pullman, Commissioner/Panel Chair
D.A. Cote, Commissioner
M.R. Harle, Commissioner

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EXECUTIVE SUMMARY

In this Decision the Commission considers an application by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW") (collectively, "Terasen") regarding Return on Equity and Capital Structure.

TGI requested a change in the common equity component of its capital structure from 35.01 percent to 40 percent and that the increased common equity component be included in the setting of its rates effective January 1, 2010.

The Commission considered, among other matters, its jurisdiction, the fair return standard, evidence on TGI's business risks, and credit ratings and metrics and concluded that TGI's business risk had increased since 2005 and that the appropriate equity ratio for TGI was 40 percent effective January 1, 2010.

TGI also requested an increased in its return on equity ("ROE") from the existing 8.47 percent to 11 percent for rate setting purposes, and that the new ROE for TGI be used in establishing the ROE for TGVI and TGW for rate setting at a premium of 70 basis points and 50 basis points respectively over TGI's ROE, and that the revised ROE for TGI, TGVI and TGW be effective July 1, 2009.

The Commission considered the various approaches used to determine ROE and the expert evidence called on behalf of Terasen and of the Intervenors on ROE. It concluded that primary weight should be accorded to the Discounted Cash Flow approach, lesser weight to the Equity Risk Premium approach (including the Capital Asset Pricing Model) and minimal weight to the Comparable Earnings approach. The Commission concluded that the appropriate ROE for TGI is 9.50 percent. Noting that the Intervenors did not oppose the request that the ROE be effective July 1, 2009 the Commission granted that request.

The July 1, 2009 effective date results in the ROE for TGI for 2009 being 8.47 percent for six months and 9.50 percent for six months, or an average annual ROE of 8.98 percent. The ROEs for TGVI and TGW become on average respectively 60 and 50 basis points higher as a result of the Commission's conclusion on their level of business risk compared to that of TGI.

The Commission considered evidence on whether the existing automatic adjustment mechanism used in the determination of the ROE of TGI, TGVI and TGW still met the fair return standard and determined that it did not. The automatic adjustment mechanism would only have produced an ROE of 8.43 percent for TGI in 2010 compared to the 9.50 percent determined by the Commission. The Commission has accordingly directed that the automatic adjustment mechanism be eliminated. However, it has also directed TGI to complete its study of alternative formulae and report to the Commission by December 31, 2010.

The Commission declined to continue to allow TGVI a premium of 70 basis points over TGI's ROE. It determined the premium should be reduced to 50 basis points as a result of a reduction in TGVI's risk since 2005. TGW was allowed a risk premium of 50 basis points over TGI's ROE.

The Commission has also determined that the ROE for TGI will continue to serve as the Benchmark ROE for FortisBC and any other utility in BC that uses the Benchmark ROE to set rates.

1.0 INTRODUCTION

On May 15, 2009 Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI"), and Terasen Gas Whistler Inc. ("TGW") filed an application under sections 59 and 60 of the *Utilities Commission Act* with the British Columbia Utilities Commission (the "Application"). In this Decision the three utilities are collectively referred to as "Terasen"; the *Utilities Commission Act* as the "*Act*" or "*UCA*"; and the British Columbia Utilities Commission as the "Commission" or "BCUC."

The Application seeks the following relief:

- that the Commission determine an increased return of 11 percent on common equity ("ROE") for TGI for rate-setting purposes, that the so determined ROE for TGI be used in establishing the ROE of TGVI and TGW used for rate-setting, and that the revised ROE for TGI, TGVI and TGW be effective July 1, 2009;
- that the Commission eliminate the use of an ROE automatic adjustment mechanism ("AAM") in the determination of the ROE to be used by Terasen for rate-setting;
- that, in replacement of the use of an AAM in the determination of their ROE, the ROE determined in the proceeding to be appropriate for TGI be used as the benchmark or generic ROE ("Benchmark ROE") for the determination of the ROE of TGVI and TGW. TGVI and TGW request that the Commission continue to set their respective allowed returns on equity with reference to the Benchmark ROE established in the proceeding by adding a utility specific risk premium of 70 basis points in the case of TGVI and 50 basis points in the case of TGW to the Benchmark ROE;
- that the Commission alter and increase the common equity component of TGI's capital structure for rate-setting purposes from 35.01 percent to 40 percent and that the increased common equity component be included in the setting of TGI's rates effective January 1, 2010;
- that the Commission set the current rates of TGI and TGW as interim, effective July 1, 2009, until such time as permanent rates are established which give effect to the relief requested; and
- that, pursuant to the provisions of the Special Direction [issued to the Commission under section 7 of the *Vancouver Island Natural Gas Pipeline Act*], the increase in TGVI's allowed ROE resulting from the Commission's determinations in this proceeding be treated as an increase to TGVI's cost of service, effective July 1, 2009, which will result in an adjustment

to the 2009 Revenue Deficiency or Revenue Surplus and will be reflected in the Revenue Deficiency Deferral Account ("RDDA") balance.

The process the Commission followed to hear the Application is described in greater detail in Appendix A to this Decision.

The allowable return on a utility's invested capital is a combination of two factors when determining a fair return:

1) the percent of its invested capital that is held as equity relative to the percent held as debt, that is, its capital structure; and
2) the rate of return allowed on the equity portion of the capital structure.

Kathleen C. McShane provided expert evidence on behalf of Terasen on capital structure and fair return on equity. Her testimony is found at Exhibit B-1, Tab 3. Ms. McShane refers to this combination when she states that, "varying both capital structures and ROEs is used by the BCUC" and is one approach to determining a fair return (Exhibit B-1, Tab 3, p. 21). She also states that, "the capital structure and the return on equity are inextricably linked." (Exhibit B-1, Tab 3, p. 3)

The capital structure and ROE for Terasen are established by the Commission for use in the calculation of rates. The actual achieved ROE and return on invested capital for a given year may differ from the ROE established by the Commission for that year because of such factors as variances between actual and forecast revenues or costs of service.

Since 1994 the Commission has annually set the ROE for utilities in British Columbia based on the Benchmark ROE for TGI using a formula that ties the utilities' rates of return on equity to the forecast yield on long-term Canada (30 year) bonds for the forthcoming year. This formula has commonly been referred to as the AAM. The capital structure of utilities has been reviewed less frequently, generally when there has been an application to the Commission for such a review. The background of ROE awards in BC, Canada, and the US since 1994, including the use of a formula to establish ROE is set out in Appendix B to this Decision.

Terasen submits that:

- The fair return standard is not being met;
- The formula that produces the ROE is "broken";
- The recent turbulence in credit markets has further highlighted the formula's flaws; and
- TGI's business risks are increasing.

Combined, in Terasen's view, these four realities mean that the results of the current formulaic approach to ROE are inadequate, and the current equity component in the capital structure of TGI should be increased. Terasen urges the Commission to update both the Benchmark ROE and TGI's capital structure and make the required determination to enable utilities in BC to operate from a healthy and sustainable foundation and continue to appropriately serve the public interest.
(Exhibit B-1, pp. 9, 10)

The Joint Industry Electricity Steering Committee ("JIESC") submits that the fair return standard is being met, that TGI's business risks have not increased, and the AAM has demonstrated remarkable strength in the face of the largest disruption to financial markets in the last 70 years. This is in part evidenced by the $900 million premium (1.7 times the net book value of the equity) paid by Fortis Inc. for Terasen Inc. ("TI") (the parent company of the three Terasen utilities) in the spring of 2007 and by TGI's ability to issue $100 million in debt in February 2009. (JIESC Argument, p. 4)

In order to assess the reasonableness of the relief sought by Terasen, it is necessary to consider the legal and regulatory bases for determining an appropriate capital structure and ROE, and the issues flowing therefrom. These considerations are made in the context of the recent economic situation, including the challenges in financial markets in 2008-2009, as well as recent relevant regulatory developments, particularly the 2009 National Energy

Board ("NEB") Trans Quebec & Maritimes Pipeline Decision RH-1-2008 ("TQM Decision"), the NEB's Reasons for Decision-review of the Multi-Pipeline Cost of Capital Decision (RH-2-94) dated October 8, 2009 ("NEB Letter Decision"), in which it determined that the RH-2-94 Decision will not continue in effect, that is, the return on equity for the pipelines regulated by the NEB will not be determined by an automatic adjustment mechanism, and the Alberta Utilities Commission ("AUC") 2009 Generic Cost of Capital Decision, Decision 2009-216 ("AUC Decision 2009-216") issued on November 12, 2009.

This Decision is divided into the following Sections which address the issues that the Commission Panel needs to determine:

Section 2.0 - Jurisdiction and the Fair Return Standard

This Section discusses the following issues: What are the interests of the parties and the Commission's obligations under the *Utilities Commission Act?* What is the fair return standard and how does the Commission Panel determine whether it is currently being met? Are US data relevant in this determination? If the fair return standard is not being met for TGI, how should the Commission Panel proceed to ensure that it is met?

Section 3.0 - Risks and Capital Structure

This Section discusses the following issues: Have TGI's risks increased since 2005 and if so how should this be reflected in TGI's capital structure? What is TGI's appropriate capital structure?

Section 4.0 - The Appropriate Return on Equity for TGI

This Section discusses the following issues: Given TGI's capital structure what is the appropriate ROE for TGI and what approaches to its determination should the Commission Panel give weight?

Section 5.0 - The Automatic Adjustment Mechanism

This Section discusses the following issues: Given TGI's appropriate ROE, does the Commission's AAM produce an ROE that meets the fair return standard? If not, should the Commission retain, amend, or eliminate its AAM?

Section 6.0 - The Appropriate Return on Equity for TGVI and TGW

This Section discusses the following issue: Given TGI's appropriate capital structure and ROE what are the appropriate ROEs for TGVI and TGW?

Section 7.0 - TGI as the Benchmark Utility

This Section discusses the following issue: What impact should the Commission Panel's determination have on the remaining utilities in BC that might be affected, namely, FortisBC Inc. ("FortisBC") and Pacific Northern Gas Ltd. ("PNG")?

2.0 JURISDICTION AND THE FAIR RETURN STANDARD

In this Section the following issues are addressed:

- What are the interests of the parties and the Commission's obligations under the *Act*?
- What is the fair return standard and how does the Commission Panel determine whether it is currently being met?
- Are US data relevant in this determination?
- If the fair return standard is not being met for TGI, how should the Commission Panel proceed to ensure that it is met?

2.1 The Interests of the Parties and the Commission's Obligations under the *Act*

Terasen states that the impact of its Application is to increase TGI's revenue requirements by $44.9 million, an increase of approximately 3.6 percent ($38 per year) to the annual bill of a TGI residential customer in the Lower Mainland. Further, Terasen states that the impact can be broken down as follows:

Company	Impact of 1% Equity Increase ($000)	Impact of .25% ROE Increase ($000)
TGI	$2,400	$3,100
TGVI	N/A	$800[(1)]

(1) Terasen notes that the revenue requirement increase for TGVI may not necessarily translate to a customer rate impact because of the soft cap mechanism.

(Source: Exhibit B-3, BCUC 3.5, 3.6)

The Intervenors take exception to the timing and amount of the increases being sought. Counsel for JIESC characterizes them as "worse than unreasonable, they are blatantly opportunistic and must be denied" (T2:23). The British Columbia Old Age Pensioners Organization *et al.* ("BCOAPO") submits that, "these increases would occur despite the Applicant…providing the exact same service quality and reliability as it currently does. In other words, it represents money for nothing." (BCOAPO Argument, para 1)

It is clear that Terasen has a significant interest in receiving the relief sought in the Application and the Intervenors have a significant stake in minimizing it.

Terasen has made the Application pursuant to sections 59 and 60 of the *Act*. Those sections are quoted in their entirety in Appendix C to this Decision.

Under section 60(1)(b) of the *Act*, when setting a rate the Commission must have due regard to the setting of a rate that:

(i) is not unjust or unreasonable within the meaning of section 59;

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands; and

(iii) encourages public utilities to increase efficiency, reduce costs, and enhance performance.

Under section 59(5) of the *Act* a rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; and

(c) unjust and unreasonable for any other reason.

The Industrial Customer Group ("ICG") submits that the *Act* requires the Commission to balance the interests of the parties and set a just and reasonable rate that provides the utility with a fair return on the rate base. ICG submits that section 59 of the *Act* explicitly requires the Commission to consider the rates from the customer perspective, specifically whether the proposed rate is fair and reasonable for the nature and quality of the service. Part of that consideration must include the economic impact of the rate for the service on customers. The Commission's primary responsibility is to regulate rates as a surrogate for competition and to keep rates within the reasonableness one would expect in a properly functioning market. Considering the customer perspective is one-half of the balance equation in a regulated environment. When acting as the surrogate for competition, the Commission cannot and must not protect Terasen from all competitive risk by raising the ROE at the expense of customers. Doing so would ignore the interest of the customers who are captive to the monopoly. (ICG Argument, p. 5)

Terasen submits that the following quotation from page eight of the Commission's 2006 Decision on Terasen's ROE, Capital Structure and the AAM ("2006 ROE Decision") correctly sets out that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital:

> "The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital." (Terasen Reply, para 6)

2.2 The Fair Return Standard

Terasen cites the TQM Decision, which summarizes the fair return standard at page 6:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)." (Terasen Argument, para 12)

Terasen and the Intervenors address the fair return standard from the perspectives of the return on invested capital of the utility, the return on the equity, the level of financial risk, the creditworthiness and financial integrity of the utility, and, on the premium paid over book value for TI by Fortis Inc. in 2007.

In her evidence, Ms. McShane states: "The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes." (Exhibit B-1, Tab 3, p. 3)

Ms. McShane addresses the maintenance of the creditworthiness and financial integrity of the utility and opines that the capital structure of TGI, in conjunction with the returns allowed on its sources of capital, should provide the basis for a stand-alone investment grade debt ratings in the A category. Debt ratings in the A category assure that Terasen should be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. (Exhibit B-1, Tab 3, p.26; Terasen Argument, para 101)

The Intervenors do not disagree with the A rating but observe that Terasen has enjoyed an A rating for many years. (JIESC Argument, p. 12)

JIESC points out that:

- in 2007, Fortis Inc. "purchased the TGI equity (sic) paying a premium of $900 million for it. A premium over book value upon which Terasen is not permitted to allow either a debt or equity return. This amounts to 1.7 times the equity value";
- in February 2009, a time when "debt markets were still recovering from the 2008 financial turmoil" TGI was able to issue $100 million debt; and

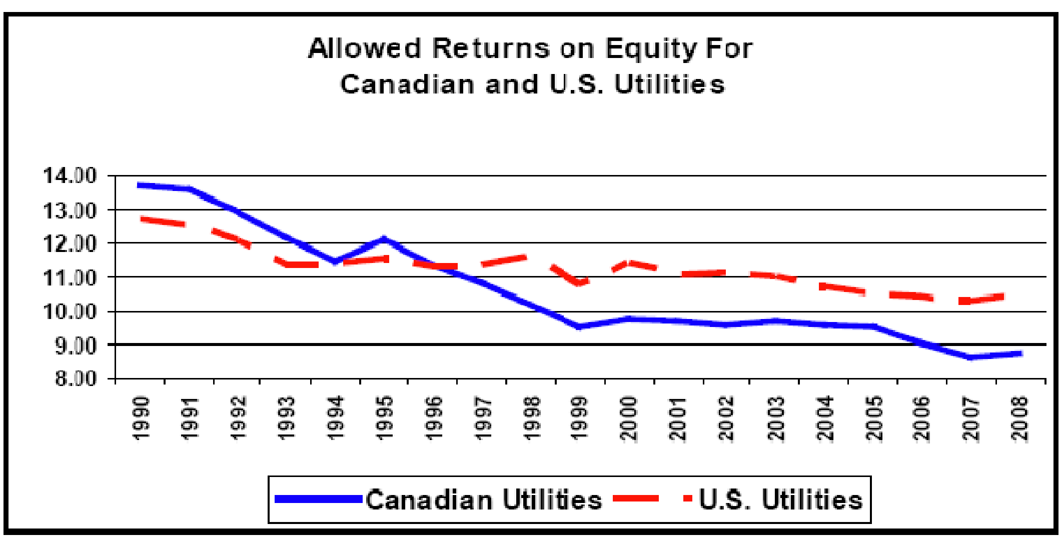
- in May 2009 TGI's bond rating was confirmed at "A" by both DBRS Limited ("DBRS") and Moody's Investors Services ("Moody's"). (JIESC Argument, p. 13)

Terasen points out that TGI's Moody's rating actually is A3 and submits that the rating is "only one notch above BBB+, which is a level at which even Dr. Booth believes TGI should not be." (Terasen Reply, para 82)

Terasen also addresses the issue of acquisition premia and refers the Commission to its 2006 ROE Decision where the Commission addressed the acquisition of TI by Kinder Morgan Inc. ("KMI") and stated at page 13: "There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination." (Terasen Reply, para 94)

2.3 The Applicability of US Data in Determining the Fair Return Standard

Terasen provides the following chart to compare the differences between ROEs allowed to electric and natural gas utilities by state regulatory agencies in the US with the ROEs allowed by Canadian regulatory agencies:



(Exhibit B-1, p. 14)

Terasen includes two reports as appendices to the Application:

i) a report sponsored by the Ontario Energy Board ("OEB") entitled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" dated June 14, 2007 and authored by Concentric Energy Advisors ("CEA") (the "CEA Report"); and

ii) a report sponsored by the Canadian Gas Association ("CGA") entitled "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis" authored by National Economic Research Associates, Inc ("NERA") dated February 2008 (the "NERA Report").

The CEA Report made ten conclusions, of which three are germane:

1. "(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing US companies or other provinces' utilities that would explain the difference in ROEs";

2. "(7) Other market related distinctions and resulting financial risk differences, particularly between Canada and the US, do exist. These factors, including differences in market structure, investor bases, regulatory environments, and other economic factors may have an impact on investors' return requirements for Canadian versus US utility investments. However, through analysis and interviews with key market participants, representatives of customer groups, and other individuals with past involvement in ROE proceedings in Canada and the US, these differences are determined to be negligible"; and

3. "(9) As a result of the interplay between the Canadian and US markets, Canadian utilities compete for capital essentially on the same basis as utilities in the US." (Exhibit B-1, Appendix 3)

The NERA Report concludes, in part:

> "We find that the regulatory institutions and customs for setting regulated prices for investor owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions…"

"We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences in Figure 1 [A Figure showing the Allowed Return Differential (Canada - US) for Gas Distribution Utilities in the period 1992-2007]." (Exhibit B-1, Appendix 4, Executive Summary)

Terasen filed the evidence of Mr. Donald A. Carmichael, a financial consultant and advisor, as Tab 2 to the Application. His opinion evidence addresses the integration of markets and competition for capital. Mr Carmichael states that the globalization of Canadian capital markets and the removal of various personal and institutional restrictions on foreign investment have caused the Canadian and international capital markets to become substantially more integrated than in the past, and points to the fact that:

- many of Canada's largest institutional investors have become major players on international stock markets and non-Canadian private equity situations;
- the market in Canada for the new issuance of foreign bonds and debentures has grown rapidly reflecting Canadian lenders' desire to diversify their portfolios with new issuers and to achieve higher returns than those available from domestic issuers; and
- the funding requirements for announced infrastructure projects in Canada will be significant and will directly compete with debt and equity financing for utilities. (Exhibit B-1, Tab 2, pp. 32-35)

Terasen submits that restrictions on foreign investments by Canadians have been removed and that competition for capital is not constrained by provincial or national borders. Canadian and international capital markets have become more integrated than in the past. Large amounts of capital are required for infrastructure projects in Canada and around the world. Terasen submits that TGI's capital structure and return on equity must be comparable to other companies of similar risk to allow it to successfully compete for capital. (Terasen Argument, para 19)

The NEB addressed the issue in the TQM Decision where it stated:

> "In the Board's view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the Board is of the view that Canadian firms are increasingly competing for capital on a global basis.
>
> A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. …As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place." (TQM Decision, pp. 66-67)

In addition, the AUC stated that it would, "review the market based return data available on the record in respect of the sample US utility proxy groups and employ this data in its CAPM [Capital Asset Pricing Model] and DCF [Discounted Cash Flow] determinations." (AUC Decision 2009-216, para 205)

Terasen submits that global competition for capital means that TGI's capital structure must be comparable to its North American peers. In Terasen's view, the TQM Decision recognizes this capital requirement, which should also be recognized by the Commission. (Terasen Argument, para 95)

In the 2006 ROE Decision the Commission addressed what it saw as the two issues of relying on US data to establish appropriate capital structures and ROEs for utilities. On the first issue (i.e. that there are opportunities for Canadian investors to commit capital globally) the Commission noted that Canadian investors faced a considerable foreign exchange risk when investing and was not convinced that the Federal Government's relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

On the second issue (i.e. that in measuring the risk premium it is necessary to look beyond Canadian data) the Commission stated that it was prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when those data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data give unreliable results; based on the fact that the US and Canadian economy and capital markets were closely integrated. (2006 ROE Decision, p. 50)

BCOAPO submits that "select US utilities...are not useful in determining comparable returns and comparable risk." (BCOAPO Argument, para 7)

Dr. Laurence Booth provided a written opinion of the fair return for TGI on behalf of the Intervenors. In his evidence, Dr. Booth states: "The message from these….disasters of US regulatory policy [i.e. the bankruptcy of Pacific Gas and Electric; the Enron and WorldCom frauds; the failure of US entities such as Lehman Brothers; and 'stock market disasters represented by pipelines like Duke Energy'] is that the US is not Canada, no matter what American witnesses before the Canadian regulatory tribunals seem to think. Regulation in the US has followed a different path to that in Canada, as is patently obvious to anyone who looks at its results. Drawing any insights from how investors perceive US utilities (or banks) given this different regulatory approach in my judgment is of very little value. I would strongly advise Canadian regulatory tribunals to ignore the advice of experts, who have US experience in mind when they from (sic) their judgments. Instead, they should focus on Canadian solutions that have worked rather than US solutions that have resulted in disaster." (Exhibit C11-5, p. 103)

Terasen submits that the evidence demonstrates that Dr. Booth's attempt to use Enron and WorldCom as examples of light-handed US utility regulation fails; neither Enron nor WorldCom were US utilities or utility holding companies, and Dr. Booth's citation of Enron, WorldCom, or Duke Energy fails to support the argument that the Commission should not consider US utilities in its determination of a fair return on equity. (Terasen Argument, para 352-53)

Commission Determination

In view of the fact that no party took issue with the articulation of the fair return standard by the NEB in the TQM Decision, the Commission Panel endorses it. It also agrees with Terasen that the combination of the equity ratio and the allowed return thereon should be adequate to attract capital on reasonable terms and conditions and allow TGI to maintain the A3 rating on its debt and unsecured debt from Moody's.

As for the Intervenors' submissions that this is not the time for a rate increase, and ICG's submission that the Commission must balance the requirements of customers with those of Terasen, the Commission Panel adopts the Commission's statement in the 2006 ROE Decision where it made it clear that its obligation was and is to set rates that are fair and reasonable, and to allow a utility the opportunity to earn a fair rate of return.

The Commission Panel has considered the premium paid by Fortis Inc. to acquire the equity capital of TI in 2007. As was the case with respect to the premium paid by KMI for the shares of TI discussed in the 2006 ROE Decision there is no evidence before the Commission that any of the premium paid by Fortis Inc. will be included in any of the Companies' rate bases and recovered from their customers. Further, as was the case with the KMI acquisition, the Commission imposed "ring-fencing" conditions upon Fortis Inc. The Commission Panel considers that the Commission's role is to determine an appropriate capital structure and return on equity for Terasen and that the acquisition of TI by Fortis Inc. is not relevant to the Commission Panel's determination in this regard.

As for the US data, the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so.

In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.

Having determined what the fair return comprises and that US data may be relevant in its determination, the Commission Panel considers that there are enough data before it to bring into question whether the fair return standard is being met in TGI's case. Accordingly, in the following sections the Commission Panel examines the evidence and determines whether an increase in TGI's equity ratio is justified, following which it determines the approaches to which it will give weight in its determination of TGI's allowed ROE. The Commission Panel examines the result of these determinations to ensure that the fair return standard is met for TGI.

3.0 RISKS AND CAPITAL STRUCTURE

This Section defines risk in the utility regulatory environment, considers TGI's business risk and determines a suitable capital structure for TGI for regulatory purposes. The following issues are addressed:

- Have the business, regulatory and financial risks of TGI increased since 2005 and, if so, how should they be reflected in TGI's capital structure?
- What is TGI's appropriate capital structure?

Terasen sets out the following reasons why TGI's common equity ratio should be increased from 35.01 percent to 40 percent:

1) TGI's level of business risk has increased;
2) there have been material increases in the allowed common equity ratios of some of TGI's Canadian utility peers;
3) its credit metrics are weak for its credit ratings, and in isolation fall below investment grade guidelines;
4) its equity ratio of 35 percent, together with lower allowed ROEs and lower corporate income tax rates have caused its interest coverage ratios to be the lowest in Canada and to continue to fall;
5) rating agencies continue to view a common equity ratio of 35.01 percent as weak. At 40 percent TGI would still lie at the lower end of Moody's guideline range for an investment grade rating on this credit metric;
6) the further global integration of the Canadian capital markets warrants a strengthening of TGI's financial parameters; and
7) the forecast North American and global investment requirements for infrastructure point to significant competition for capital going forward. TGI should be positioned so that it can compete successfully. At the existing capital structure, TGI's credit metrics compare unfavourably to those of its US peers. (Exhibit B-1, Tab 3, pp. 39-40)

The assessment of risks has significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes.

3.1 The Definition of Risk in the Utility Regulatory Environment

In discussing business risk in its Argument, Terasen refers to page 17 of the 2006 ROE Decision. At that reference, the Commission defined risk as follows:

> "The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. Investment risk comprises the sum of business risk, financial risk and regulatory risk."
>
> "Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital. Dr. Booth summarized those elements that constitute business risk as:
>
>> '…stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method used by the firm and the uncertainty in the firms' cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials.' "
>
> "Financial risk is measured through the debt equity ratio of a utility."
>
> "Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards." (2006 ROE Decision, p. 17 [references omitted]; Terasen Argument, para 23)

Terasen discusses the business risk of TGI and states that it is useful to consider short-term and long-term risks. In the short-term the focus is generally on TGI's ability to earn a fair return on its investments from year to year. In the longer term the risk relates to whether or not the utility will be able to recover the cost of its investments over their useful lives and earn a fair return on such investment over the long run. (Exhibit B-3, BCUC 14.1)

Terasen notes that business risk has both short-term and long-term aspects and that since a local distribution company's ("LDC") investments have a useful life that extends over a long period of time, it is the longer-term fundamental business risks that must be given primary consideration when evaluating the business risk of a gas distribution utility.

Ms. McShane observes that regulatory agencies in Canada have followed two separate approaches to addressing utility risk. The NEB and the AUC have adopted one approach whereby each utility subject to their jurisdiction has an individual equity ratio which is determined by its respective long and short-term business risks, to which is applied a uniform ROE. The other approach, followed by the Commission, the OEB and the *Regie de l'Energie*, is to establish the capital structure and ROE for a benchmark utility and to set capital structures and ROEs for all other utilities in their jurisdiction with reference to the benchmark. (Exhibit B-1, Tab 3, p. 21)

Commission Determination

The Commission Panel notes that no party took issue with the Commission's characterization of risk in its 2006 ROE Decision and accordingly accepts the definition for the purposes of this proceeding.

The Commission Panel accepts Terasen's characterization of its business risk as having long-term and short-term aspects and it will consider them separately in Sections 3.2 and 3.3 of this Decision.

In its 2006 ROE Decision the Commission stated: "The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities." (2006 ROE Decision, p. 36)

In this Decision, however, the Commission Panel considers the effect of deferral accounts in reducing the risk of TGI as reducing the short-term, and not the long-term, business risk of TGI, and will accordingly adjust TGI's ROE rather than its capital structure.

3.2 TGI's Long-Term Business Risk

In Tab 1 of its Application, Terasen sets out key factors that have affected TGI's business risks in recent years:

1) Provincial climate change and energy policies have increased the risk inherent to TGI's core natural gas business;
2) the effect of aboriginal rights issues on utilities in BC;
3) the competitive position of natural gas relative to electricity has been weakened;
4) TGI is capturing a smaller percentage of new construction;
5) electricity is increasingly the choice of high-density housing;
6) alternative energy sources further weaken TGI's competitive position;
7) fuel switching has also diminished demand for natural gas; and
8) the use of natural gas per (customer) account continues to decline. (Exhibit B-1, p. 24 and Tab 1)

Terasen states that the first two factors are new in that they have emerged since its last ROE application in 2005, and that the remaining key factors were identified by it as factors affecting its business risk in 2005. These risk factors are addressed below.

3.2.1 Provincial Climate Change Policies

Terasen states that the Throne Speech delivered on February 13, 2007 outlined the province's Greenhouse Gas ("GHG") reduction target. A second announcement on February 19, 2008 introduced a carbon tax in BC. These two policies and their subsequent implementation into law have increased TGI's business risk since 2005. Since the publication of, "The BC Energy Plan: A Vision for Clean Energy Leadership" ("2007 Energy Plan") in February 2007, the provincial government has taken a leadership role in the fight against climate change/global warming and, in the spring 2008 Legislative Session, introduced the following bills:

- Bill 15 – *Utilities Commission Amendment Act*;

- Bill 16 – *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*;
- Bill 18 – *Greenhouse Gas Reduction (Cap and Trade) Act*;
- Bill 31 – *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act*;
- Bill 27 – *Local Government (Green Communities) Statutes Amendment Act, 2008*; and
- Bill 37 – *Carbon Tax Act*.

Under the *Greenhouse Gas Reduction Target Act* (passed in 2007), and under Ministerial Order dated November 25, 2008, BC's GHG emission targets levels have been established as:

- 2012 6 percent below 2007 levels;
- 2016 18 percent below 2007 levels;
- 2020 33 percent below 2007 levels;
- 2050 80percent below 2007 levels. (Exhibit B-1, Tab 1, pp. 3, 5)

Terasen states that as of March 31, 2009, pursuant to a climate action charter between the Province and the Union of BC Municipalities establishing, among other things, a commitment to a goal of becoming carbon neutral by 2012, 174 local governments had become signatories. In addition the Province has set emission targets for universities, schools and hospitals.

Terasen states that TGI's risk profile has increased substantially due to the climate change challenge, the provincial GHG reduction targets, and how these targets have shaped customers' views of natural gas. In its view, there can be no doubt that these actions will have an impact on the use of natural gas, TGI's opportunities, and TGI's ability to recover its investment over the long term.

Terasen states that the BC Carbon Tax, implemented effective July 1, 2008, to help the Province reach its GHG reduction targets, reduces the competiveness of natural gas relative to alternative energy sources that are not subject to the carbon tax, and provides a direct pricing signal to customers in relation to GHG emissions. The tax started at $10/tonne of GHG and will increase by $5/tonne each year to $30/tonne by 2012. Terasen cites the BC Climate Action Team's recommendation that: "After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a manner that aligns with the policies of other jurisdictions and key economic facts." (Exhibit B-1, Tab 1, pp. 10-11).

A Terasen witness testified that "and there are calls...from certain academics and others that say in order for the government to get the consumption of GHGs down, it's going to have to move to $300. So, that's $15 a GJ [gigajoule], not $1.50, on top of the commodity and the delivery rates" (T2:155). $300 per tonne is also the carbon tax assumed by 2026 in the Nyboer Report discussed later in this Section (Exhibit B-11, Panel 1.1).

Terasen submits that the carbon tax reduces natural gas' competiveness relative to alternative energy sources that are not subject to the carbon tax and will help to sensitize customers to the level of GHG emissions they generate by sending them price signals. The provincial carbon tax increases the business risks of TGI. (Terasen Argument, para 52)

Terasen states that government policy that discourages consumers from using natural gas will have the effect of reducing throughput volumes on the TGI system and reducing the attachment of new customers. The recovery of fixed costs from a smaller customer base, and on lower throughput, leads to rate pressure for the remaining customers. Left unmitigated and unchecked, these effects can lead to loss of existing natural gas customers and a potential "downward spiral" in which the risk of non-recovery of invested capital increases and assets potentially become stranded.
(Exhibit B-11, Panel 1.1)

Terasen filed a report entitled, "A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis," dated August 22, 2008, and prepared for the National Round Table on the Environment and the Economy by J & C Nyboer and Associates, Inc, (the "Nyboer Report") which describes itself as a "technology roadmap derived from the *Getting to 2050* deep emissions reductions pathways that simulates a 20 percent reduction in Canada's GHG emissions from 2006 levels by 2020 and a 65 percent reduction in emissions by 2050." The Nyboer Report's findings are that by 2050 virtually all residential and commercial space and water heating in BC will have migrated from natural gas to electricity. (Exhibit B-11, Panel 1.1, and Attachment 1.0)

TGI's President agreed that under this scenario TGI would be out of business by 2050, but testified "We think it's one of many (possible scenarios). Our concern is what degree of influence it seems to be having in certain circles amongst policy makers." (T3:279-80)

Terasen stated that:

> "Reports of this type to policy makers, with access by consumers, can and does shape the long-term view of policy makers and the broader community respecting a product (in this case, natural gas) and may well be influential in formulating public policy that has long-term negative impacts on the demand for that product (i.e. natural gas). The outcome identified in the Report would reduce throughput on the Terasen natural gas delivery systems, which all else equal, will increase the unit costs to the remaining natural gas customers. In the extreme, the Company could have stranded assets if the roadmap that is outlined in the Report materializes." (Exhibit B-11, Panel 1.1, p. 2)

TGI's President summed up his testimony as follows:

> "We believe that natural gas is a foundational fuel, not a transitional fuel, but we're not sure that all the necessary parties are in alignment with that. We have an absence of a continental carbon policy, we have an absence of a national one, and we've got a lot of vulcanization [balkanization] going on that ultimately needs to be and I think will be resolved. I'm just not sure how all the crumbs are going to fall from that. We're not sitting before this Panel saying the sky is falling. Let us be clear on that. Chicken Little is not in the hearing room...we're not here saying that this company is going out of business." (T3:227-28)

The Commercial Energy Consumers Association of British Columbia ("CEC") submits that the overall result of its evaluation of TGI's risk in 2009 versus 2005 is that significant new positive reductions of risk are now in sight, whereas in 2005 these did not exist. Offsetting this are the new provincial GHG reduction policies which would potentially limit any throughput growth for the utility.

CEC considers the net balance of these overall results to be the key focus of determining if the business risk has changed sufficiently enough to warrant a change to either the allowed ROE or the equity ratio. CEC's assessment of the evidence is: i) that TGI's business risk has not increased appreciably enough to warrant a change to allowed ROE or its equity ratio, and ii) that the Province's GHG policies are so new, and Terasen's analysis and mitigation response are so limited at this time, that Terasen has not established a persuasive case for increased business risk.

CEC submits that it would be premature for the Commission to make assumptions that the business risk surrounding TGI's inability to recover its investment capital has increased until the Commission has one or more scenario projections in evidence which lay out how the targeted reductions might unfold for Terasen and its customers. (CEC Argument, p. 15)

ICG submits that Provincial climate change and energy policies do not necessarily increase TGI's business risks as Provincial energy conservation measures affect throughput, but Terasen's profits are not dependent on volume. ICG characterizes Terasen's concerns about carbon tax impacts after 2012 as "purely speculative," and submits that: "[i]t is premature for Terasen to assume the worst, and seek to impose additional economic burden on its customers that cannot be supported by the current circumstances." (ICG Argument, p. 8)

JIESC submits that "these alleged "risks" (i.e. climate change and First Nations) must be considered in the context of their likely impact on Terasen's capability to earn a return on and a return of, its capital." To the extent there are increased risks arising out of GHGs or First Nation issues, JIESC submits that these risks are "more than offset by the improvements in the competitive position of natural gas in comparison to electricity." (JIESC Argument, p. 20)

Terasen submits that such submissions "should be seen for what they are, and that is an attempt to distract the Commission from addressing the evidence before it," and that the evidence establishes, as even CEC acknowledges, that government policies and legislation have created uncertainty and will have long-term impacts on Terasen's natural gas distribution business. (Terasen Reply, para 28)

3.2.2 First Nations

Terasen submits that the lack of certainty of the nature and extent of aboriginal rights and title in BC together with the lack of treaties combine to create operational and regulatory complexity, and a risk of litigation, that: i) are greater than those faced by similar businesses in other jurisdictions, and ii) contribute to TGI facing a higher degree of risk than utility operations in other provinces. (Exhibit B-1, p. 14)

The Intervenors characterize First Nations' risk to Terasen as "minimal" (JIESC Argument, p. 26) and of "little impact." (BCOAPO Argument, para 29)

In Reply, Terasen submits that the primary issue in respect of First Nations risks is the increase in these risks since 2005, and none of the Intervenors suggested that there has been no increase in this risk in the past five years. (Terasen Reply, para 76)

3.2.3 Other Key Factors

As for the other key factors, Terasen submits that natural gas' competitive position relative to electricity has been weakened, that TGI is capturing a smaller percentage of new construction; electricity is increasingly the choice of high-density housing; alternative energy sources further weaken TGI's competitive position; that fuel switching has also diminished demand for natural gas; and that the use of gas per account continues to decline. Terasen states that many factors have been exacerbated by the uncertainty created by the provincial climate change initiatives and the introduction of the carbon tax.

BCOAPO rejects Terasen's claim that TGI's competitive position relative to electricity in BC has decreased since 2005 and submits that the exact opposite is true, citing the introduction by BC Hydro of the Residential Inclining Block rate as having actually made natural gas more competitive relative to electricity, especially for single family dwellings. BCOAPO submits that "the alleged threat" faced by Terasen due to government policies taken as a whole is not 'profound' and has not materially increased Terasen's business risk such that their common equity ratio should be changed. (BCOAPO Argument, para 19, 20)

ICG submits that the competitive position of natural gas relative to electricity has not been weakened, and that "at the very least, Terasen is currently maintaining its competitive position with BC Hydro." (ICG Argument, p. 8)

Terasen submits that future electricity prices are uncertain due to the extent of, and cost of, resource additions and other factors, but "what is known is that BC Hydro does have major, historic low-cost, hydro-electric resources...and due to the size of those resources, relatively low electric prices will continue long into the future. On the other side of the cost comparison between the cost of natural gas and electricity to consumers is the commodity price of natural gas. It appears to be common ground between the Terasen Utilities and Intervenors that natural gas commodity prices are volatile." (Terasen Reply, para 48-49)

Terasen also submits that the submissions of the Intervenors would have the Commission believe that if the annual cost of natural gas to the consumer is less than the annual cost of electricity then TGI does not have an increase in business risk from 2005. Terasen further submits that by focusing on cost comparisons the Intervenors' submissions fail to take into account the uncertainty and business risks associated with non-cost factors such as public perception and changes in behaviour that are required by government regulation. According to Terasen: "There can be no doubt that the mantras of provincial government energy policy are the promotion of 'clean' forms of energy, such as 'clean electricity,' and the reduction in GHG emissions." (Terasen Reply, para 57)

3.3 TGI's Short-Term Business Risk

Terasen provides a comparison of TGI's earned ROE with its allowed ROE for the years 1992-2008. In the 15 years since the introduction of the AAM in 1994 the comparison shows that it has earned more than its allowed ROE in 13 years and earned less in two years. TGI's allowed and achieved

ROEs for the years 2004-2009 are set out in the table below. In these years, TGI has been operating under a performance based regulation regime under which it shares any over-achievements with its customers. (Exhibit B-6, BCUC 91.1)

Year	Allowed ROE (%)	Achieved ROE (%) Pre-sharing	Achieved ROE (%) Post-sharing	Incentives Earned ($000)
2004	9.15	9.344	9.247	1,179
2005	9.03	10.784	9.907	6,969
2006	8.80	10.472	9.636	7,147
2007	8.37	10.729	9.550	10,018
2008	8.62	10.637	9.628	8,726

(Source: Exhibit B-6, BCUC 91.1)

Terasen states that in July 2003 TGI received Commission approval of a negotiated settlement for a 2004-2007 Performance Based Review (“PBR”) which established a process for determining its delivery charges and incentive mechanisms for improved operating efficiencies and included incentives for it to operate more efficiently through the sharing of the benefits between it and its customers.

The PBR Settlement included ten service quality measures designed to ensure TGI maintained adequate service levels and set out the requirements for an annual review process between TGI and interested parties regarding its current performance and future activities. The PBR Settlement provided for a 50/50 sharing mechanism of earnings above or below the allowed return on equity beginning in 2004.

Terasen states that in 2007 TGI applied to extend the 2004-2007 PBR Settlement agreement to 2008-2009, which the Commission approved (Exhibit B-3, Attachment 39.1), and that with the expiry of PBR and related incentive earnings, it becomes more important that the Commission ensure that TGI’s investors are afforded a fair return. (Exhibit B-3, BCUC 39.2)

TGI's short-term business risk and its ability to earn a return on its capital in the short-term is affected by the Commission's approval of a number of deferral accounts which permit TGI to defer variances relating to gas commodity costs, the effect of weather, variations in residential and commercial customer usage and certain expense categories such as property taxes and short-term interest rates.

TGI provided the following table showing the dollar value and percentage of its 2009 total revenue requirement and its 2009 delivery margin revenue requirement covered by deferral accounts:

	Revenue Requirement		Revenue Requirement Covered by Deferred Charges			Revenue Requirement Not Covered by Deferred Charges	
Revenue Requirement Item	$000's	% of Total	% Covered by Deferred Charges	($000's)	% of Total Revenue Requirement	($000's)	% of Total Revenue Requirement
Cost of Gas	$ 1,187,999	70.3%	100.0%	$ 1,187,999	70.3%	$ -	0.0%
Operation & Maintenance Expenses	174,942	10.4%	4.9%	8,570	0.5%	166,372	9.8%
Property and Sundry Taxes	47,593	2.8%	100.0%	47,593	2.8%	-	0.0%
Depreciation and Amortization	89,685	5.3%	0.0%	-	0.0%	89,685	5.3%
Other Operating Revenue	(23,444)	-1.4%	4.3%	(1,000)	-0.1%	(22,444)	-1.3%
Income Taxes *	26,331	1.6%	0.0%	-	0.0%	26,331	1.6%
Interest	110,953	6.6%	94.4%	104,691	6.2%	6,262	0.4%
Equity Earned Return	75,360	4.5%	0.0%	-	0.0%	75,360	4.5%
Total Revenue Requirement	1,689,419	100.0%		1,347,853	79.8%	341,566	20.2%
Total Delivery Margin Revenue Requirement	501,420	100.0%		159,854	31.9%	341,566	68.1%

* Since deferral accounts are maintained on a net-of-tax basis, to the extent any amounts were charged to or credited to deferral accounts, there would be an offsetting income tax impact

(Exhibit B-3, BCUC 88.2)

Terasen submits that TGI's deferral accounts have changed little since 2005, and points to the Commission's finding relating to TGI's gas commodity costs deferral accounts at page 25 of the 2006 ROE Decision that, "the vast majority of gas distribution companies in North America have some form of commodity deferral account, and that this protects both the utility from commodity risk and the customers from imprudent purchasing and from the utilities profiting from the purchase, transportation and storage of gas."

In the 2006 ROE Decision, the Commission also observed that for many of the other costs that have deferral account treatment, "that TGI is not penalized for underestimating or rewarded for overestimating a cost over which it has little or no control." Terasen submits that this observation of the Commission remains valid.

Terasen also cites the Commission's discussion of TGI's Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account in the 2006 ROE Decision, where it referred to two facets of the account, the first as a weather normalization account, and the second to enable TGI to defer margin variances arising from residential and commercial customers consuming more or less gas than forecast. As for weather normalization, the Commission was of the view that TGI was similar to a number of utilities in North America that can defer the effects of temperature on usage. Since weather is a symmetrical risk, with equal odds of over and underachieving, the Commission determined that it should not be taken into account when establishing return on equity.

The Commission considered the second facet of the RSAM to be a short-term business risk mitigant, which was not available to TGI's comparators.

Terasen points out that the RSAM does not mitigate the risk associated with TGI's forecast customer additions, as it only relates to use per account, and submits that with regard to the statement that margin variance accounts are not available to other utilities, that an increasing number of other utilities both in Canada and the US now have decoupling protection, which is required to ensure that a utility is not deterred from or economically disadvantaged by undertaking energy conservation programs. In those instances where per customer usage varies from forecast because incorrect values were accepted by the regulator, Terasen submits that the values would have been accepted with no symmetrical bias. Accordingly Terasen submits that neither facet of the RSAM should be taken into account when determining return on equity, and that the RSAM should not be taken into account in considering the long-term business risks of TGI. (Terasen Argument, para 46)

3.4 Capital Structure

All three of Terasen's expert witnesses commented on the equity ratio of TGI and compared it with major natural gas LDCs in Canada, utilities in Ontario, and US utilities.

Terasen sets out the equity ratios of the other major natural gas LDCs in Canada as follows:

Company	**Equity Ratio (%)**
TGI	35.01
ATCO Gas[1]	38.00
Union Gas	36.00
Enbridge Gas ("EGDI")	36.00
Gaz Metro	38.50

(1)ATCO Gas' equity ratio was increased to 39 percent by AUC Decision 2009-216.

(Source: Exhibit B-1, p. 13)

Ms. McShane also observes that ATCO Gas, Union Gas and EGDI all have preferred shares in their capital structures, whereas TGI does not, and that since 2005, the NEB has approved increases in the equity ratios of a number of gas pipelines it regulates. (Exhibit B-1, Tab 3, pp. 32-33)

Ms. McShane testified that TransCanada's increase of equity ratio to 40 percent was a result of a negotiated settlement and that she was not aware of what was traded off in return for the increase. She acknowledged that she was not aware of any regulatory agency putting weight on the equity ratios that come out of negotiated settlements. (T4:475-77)

Mr. Carmichael recommends that the Commission increase TGI's deemed equity base to at least 40 percent to achieve an appropriate stand alone financing structure. According to Mr. Carmichael, such an increase would be consistent with decisions in other Canadian regulatory jurisdictions, and primarily in Ontario, which has chosen to increase the common equity bases of i) natural gas LDCs to 36 percent for Union Gas and EGDI (in addition to their preferred shares) and ii) electric LDCs to 40 percent for Toronto Hydro and other major LDCs. The increase would also recognize that TGI must compete for debt and equity funds against thicker equity capitalized gas distribution companies from the US. (Exhibit B-1, Tab 2, p. 50)

Dr. James H. Vander Weide was retained by Terasen to: i) assess the validity of the AAM, ii) conduct an analysis of the cost of equity for TGI, and iii) recommend an appropriately fair ROE and deemed equity ratio for TGI. In his filed evidence he states that during the period 2006-08 the average approved equity ratio for US electric utilities, and for US natural gas utilities, was 48 percent and 49 percent, respectively, and that these were significantly higher than the approved equity ratio for TGI. (Exhibit B-1, Tab 4, p. 35)

JIESC submits that the only relevant changes in common equity ratios are the changes for Union Gas and EGDI, whose common equity ratios have both increased from 35 percent to 36 percent since 2005 (with the increase in Union Gas's common equity ratio being, "the result of a negotiated settlement under which presumably the interveners received value"). Since it considers TGI to be less risky than these utilities, it submits that TGI should continue to have a lower equity ratio. (JIESC Argument, p. 29)

In Reply, Terasen submits that Union Gas and EGDI have less business risk in that electric prices in the service areas of Union Gas and EGDI are higher than BC Hydro prices, and in that neither Union Gas nor EGDI are subject to government policies and legislation similar to the energy-related policies of the BC provincial government. Terasen submits that the risks of TGI are greater than those of both Union Gas and EGDI. (Terasen Reply, para 84)

3.5 Credit Ratings and Metrics

Terasen states that TGI's debt is currently rated by all three major debt rating agencies, Moody's, DBRS, and Standard & Poor's (on an unsolicited basis only), and that Moody's debt rating of A3 for TGI's senior unsecured debentures is the lowest rating of the three agencies and is only one level above the Baa rating category. Since it believes that bond investors are more likely to focus on the lowest rating, TGI focuses on Moody's ratings and guidelines. (Exhibit B-1, Tab 3, p. 33)

Terasen filed a Moody's report entitled *"Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies),"* dated October 2006 which covers 30 gas utilities in North America (Canada and the United States). (Exhibit B-6, BCUC Attachment 111.1, p. 1)

Moody's states that the focus of its rating methodology is on the "pure" gas LDCs in North America and is concerned principally with operating utilities regulated by their local jurisdictions and not with gas utilities owned by parent holding companies that have other non-regulated businesses. TGI is the only Canadian utility included in the report, which focuses on the following core rating factors:

- sustainable profitability;
- regulatory support;
- ring fencing; and
- financial strength and flexibility.

In addition, the report analyzes factors that are common across all industries such as liquidity, corporate governance, event risk, and legal structure.

The report describes the methodology used to rate a gas utility company which focuses on the following factors and gives them the following weights:

- Sustainable Profitability
  - Return on Equity (15 percent)
  - EBIT [Earnings before Income Taxes] to Customer Base (5 percent)

- Regulatory Support
  - Regulatory Support and Relationship (10 percent)

- Ring Fencing
  - Ring Fencing (10 percent)

- Financial Strength and Flexibility
  - EBIT/Interest (15 percent)
  - Retained Cash Flow/Debt (15 percent)
  - Debt to Book Capitalization (excluding goodwill) (15 percent)
  - Free Cash Flow/Funds from Operations (15 percent).

The following table sets out TGI's ratings by Moody's and where on the "factor mapping" the ratings place TGI:

Category	**Metric/Comment**	**Indicated Rating**
Return on Equity	9%-14%	A
EBIT to Customer Base	>$350/customer	Aaa
Regulatory Support and Relationship	"Very good, proactive support"	Aa
Ring Fencing	"Very good provisions"	Aa
EBIT/Interest	1 – 2x	Ba
Retained Cash Flow/Debt	5 – 10%	Ba
Debt to Book Capitalization	65 – 85%	Ba
Free Cash Flow/Funds from Operations	(15%) – (30%)	A

The report notes with respect to TGI that: "Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8 percent, EBIT/Interest below 2x, RCF [Retained Cash Flow]/Debt below 5 percent and/or Debt/Book Capitalization (excluding goodwill) above 65 percent, would likely lead to a downgrade of TGI's rating." The report concludes that TGI's model rating would be a Baa1.

In its May 2009 report affirming TGI's A3 rating, Moody's cautions:

> "However, in the context of the current low interest rate environment and weaker economy, Moody's is becoming concerned that TGI's credit metrics could deteriorate to levels that, despite the relative supportiveness of TGI's regulatory environment, are not commensurate with the company's existing A3 senior unsecured rating and therefore could lead to a negative rating action...Moody's will be following the progress of TGI's cost of capital application and its pending application for 2010 rates to determine their impact on TGI's financial profile." (Exhibit B-3, BCUC 1.86.2)

Terasen states that a credit rating downgrade below the A rating category could lead to TGI being required to post letters of credit with its counterparties, which would incur a direct cost in the form of letter of credit fees. In addition, and of more concern, would be the potential restriction this could place on TGI's commodity hedging activities, which can extend out three years, and where given the volatility in gas prices, the mark to market exposure on a derivative can vary significantly. When TGI enters into financial hedges, it restricts its activities to A or higher rated counterparties, and, with a B rating, could face similar restrictions and be constrained in pursuing its hedging activity, to the potential detriment of its customers. (Exhibit B-1, p. 37)

The impact of a downgrade by Moody's is also considered by Ms. McShane who opines that a downgrade increases the cost of the new debt, but also affects outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing holders are the most likely purchasers of future issues, a debt rating downgrade, with resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.
(Exhibit B-1, Tab 3, p. 27)

JIESC submits that TGI's consistent "A" bond ratings are due to the regulatory regime and the constancy of TGI's earnings and do not appear to be in jeopardy. The JIESC submits that if the Commission does conclude that TGI's "A" rating is in jeopardy, it should "pick a low cost alternative to protect it, like the issuance of preferred shares rather than increase the equity ratio." JIESC also points out that while TGI may appear to have weak credit metrics in comparison to US utilities, it has a higher bond rating than most US utilities and submits that the credit rating which looks at utilities' total risk profile is more important than credit metrics, which represent one item assessed in determining the bond rating. (JIESC Argument, pp. 29-30)

In Reply, Terasen submits that preferred shares are inefficient, and not the appropriate means of addressing credit rating metrics, since: i) Moody's views such preferred shares more as debt instruments, and therefore the issuance of preferred shares would not address concerns with credit rating metrics, and ii) the dividends on preferred shares are not tax deductible, on a debt equivalent basis, the debt component is an expensive form of debt. (Terasen Reply, para 83)

3.6 Interest Coverage Ratios

Terasen states that TGI currently has one of the weaker credit metrics of the sample Canadian utilities, and is lower than the group average. Terasen compares TGI's interest coverage ratio with those of its Canadian peers as follows:

Utility	2005	2006	2007	2008
EGDI	2.29	1.80	2.24	2.27
Gaz Metro	2.65	2.45	2.30	2.21
Union	2.09	1.91	2.24	2.28
TGI	1.94	2.00	1.95	1.96

(Source: Exhibit B-1, Table 7.4, p. 40)

Terasen states that TGI's trust indenture provides that TGI will not issue debentures or other debt instruments other than Purchase Money Mortgages ("PMM") maturing 18 months or more after date of issue unless consolidated available net earnings are at least two times the annual interest requirements on all additional obligations (including the additional debt to be issued).

Terasen states that TGI has outstanding PMMs totalling approximately $275 million, which fall due in 2015/16 and that, while a determination has not been made, it is currently of the view that it may not be able to reissue the PMM's on maturity with the result that they will be refinanced with unsecured debentures. Since the PMM's are not subject to the issuance coverage test, while the unsecured debentures that refinance them would be, Terasen states that the refinancing of its PMM's on their maturity will lead to further constraints on the issuance coverage test.

Terasen provides Exhibit B-28, which discusses the coverage test and attaches a table which demonstrates that at 35 percent equity and an 8.43 percent ROE it would have difficulty in issuing $100 million of unsecured debt in 2009. (Exhibit B-28)

Commission Determination

Based on the Commission's assessment of TGI's long-term business risk in its 2006 ROE Decision, the fact that TGI has no preferred shares in its capital structure, and a comparison with the other major natural gas LDCs in Canada, the Commission Panel considers that the equity ratio of TGI, remains in the range of 35 percent to 38 percent before considering the impact of any change in TGI's long-term business risk that has occurred since 2005.

The Commission Panel agrees with the Intervenors that all risks cited by Terasen existed in 2005 with the exception of the climate change related risks and those related to First Nations.

As for the existing risks, the Commission Panel does not see how TGI's ability to earn a return on or of its capital has been adversely affected since 2005. Although all Intervenors identify the competitive position of natural gas compared with electricity as one risk which has diminished since 2005, the Commission Panel considers that natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent.

As for concerns about the risks posed by First Nations, the Commission Panel agrees with Terasen that the risks did not exist in 2005, to the extent they are currently perceived, and that they constitute an increase in risk over natural gas LDCs operating in other provinces. The Commission Panel does not consider that the risks presently cast doubt over TGI's ability to earn a return on or of its capital.

The Commission Panel agrees with Terasen that the introduction of climate change legislation by the provincial government has created a level of uncertainty that did not exist in 2005 and that the change in government policy will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity. In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers.

As for the evidence that US natural gas LDCs have thicker equity ratios than their Canadian counterparts, the Commission Panel notes that no reasons for the difference were entered into evidence. The Commission Panel concludes that the difference between US and Canadian natural gas LDCs' equity ratios is not of itself determinative.

The Commission Panel considers that TGI's business risk has increased since 2005. In the Commission Panel's opinion the additional risk suggests an equity ratio for TGI of 40 percent. **Accordingly, the Commission Panel determines that the appropriate equity ratio for TGI is 40 percent effective January 1, 2010.**

As it did in its 2006 ROE Decision, the Commission Panel requires TGI to file within 30 days of this Decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission in its Order G-49-07.

4.0 THE APPROPRIATE RETURN ON EQUITY FOR TGI

The issue that is addressed in this Section is: Given TGI's capital structure, what is the appropriate ROE for TGI and what approaches to its determination should the Commission Panel give weight?

There are several approaches used to determine ROE, none of which is universally preferred. Therefore, in order to determine the appropriate ROE for TGI, the Commission Panel must first review the main approaches for determining an appropriate ROE and decide how much weight to accord the results from each.

The approaches are reviewed in Section 4.1, below. Once they have been reviewed and the Commission Panel has determined how much weight to give to each, it then reviews, in Section 4.2, the results from each of the approaches as calculated by the various experts, to determine the appropriate ROE for TGI.

4.1 The Approaches used to Determine ROE

Terasen identifies three approaches used to determine ROE:

1) Discounted cash flow ("DCF");
2) Equity risk premium ("ERP");and
3) Comparable earnings ("CE").

Ms. Mc Shane states that: "Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of estimating the fair return; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return." (Exhibit B-1, Tab 3, p. 42)

4.1.1 Discounted cash flow approach

Terasen submits that the discounted cash flow approach for the determination of the return on equity of regulated utilities is an approach that has been widely accepted, and widely used for many years, even though in recent years the use of the DCF approach by Canadian regulatory agencies has been limited. Terasen cites an article by Dr. Makholm from ***Public Utilities Fortnightly*** dated May 15, 2003 entitled, "In Defence of the Gold Standard," where Dr. Makholm stated that, "the DCF method has endured [in the US] for most of the past two decades for three basic reasons:

- It rests on a solid, straightforward theoretical base;
- It capitalizes on the depth of U.S. capital markets-meaning analysis can use "proxy groups" of publicly traded companies in the same industry to manage the variability of individual company DCF calculations; and
- It makes use of company growth projections from disinterested industry analysts-a key attribute for a method to gauge the opportunity cost of capital in the mind of investors." (Exhibit B-20)

Dr. Booth states that, "…the DCF estimate is particularly appropriate for use in determining the fair rate of return for a regulated utility." (Exhibit C11-5, Appendix C, p. 4)

JIESC submits that, "By comparison [with the Capital Asset Pricing Model ("CAPM")] DCF and comparable earnings are black boxes with numerous judgements and are much less constrained by the facts." (JIESC Argument, p. 2)

JIESC points out that the DCF approach has not been accepted by a Canadian regulator in the last 10 years. In addition it points out that Ms. McShane's discounted cash flow test uses a sample of US gas and electricity utilities and relies on *Value Line* and Thomson Reuters I/B/E/S ("I/B/E/S") forecasts for estimating earnings growth. The JIESC submits that "this [reliance] still suffers from the strong possibility of upward bias and should be subject to considerable caution before being used." (JIESC Argument, p. 39)

Terasen replies that there is no suggestion that *Value Line* forecasts suffer from upward bias, and that Dr. Vander Weide testified that studies that have purported to show upward bias have statistical errors.

Terasen takes issue with the characterization of the DCF and CE tests by JIESC as "black boxes" and submits that the criteria used by Ms. McShane in selecting companies of comparable risk are objective and explicit, and focus on characteristics to ensure comparability. The way the returns are measured in both the DCF and comparable earnings approaches are transparent, and the tests, in contrast to the CAPM, are compatible with meeting the comparable returns requirement. (Terasen Reply, para 104)

4.1.2 Equity Risk Premium Approach

Terasen submits that the equity risk premium test is derived from the concept that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds the equity investor requires a premium above bond yields in compensation for the greater risk.

Terasen states that the Capital Asset Pricing Model ("CAPM") is one of the equity risk premium models, and is the most common, but not the only one. CAPM is based on a portfolio investment theory and relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth), while company-specific risks, according to CAPM, can be diversified away by investing in a portfolio of securities; therefore, the investor requires no compensation to bear those risks. (Terasen Argument, para 296)

Under the CAPM approach, ROE is calculated using the following formula:

ROE = Risk-Free Rate + {Relative Risk Adjustment x Market Risk Premium}

In CAPM, risk is measured using the relative risk adjustment, known as beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on S&P/TSX Composite Index, and the returns on individual stocks or portfolios of stocks. (Exhibit B-1, Tab 3, p. 45)

Ms. McShane states that the "raw" betas for publicly-traded Canadian regulated gas and electric companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector declined significantly in the periods between 1993 and 1998 and between 1999 and 2005, and that following an increase in 2007 to 0.50, the utility betas again declined in 2008 to approximately 0.25. These "raw" betas of approximately 0.25 for Canadian utilities provide virtually no explanatory power in terms of capturing utility investors' return expectations. While that is clear, the more difficult task is to determine if and how the "raw" beta values can be translated into a relative risk adjustment that does provide an indication of the return requirements of utility investors. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened").

Ms. McShane states that the practice of adjusting betas toward the equity market beta of 1.0, rather than the calculated "raw" betas, takes account of the observed tendency of stocks with low betas to achieve higher returns than predicted by the simple CAPM and vice-versa. Adjusted betas are a standard means of estimating betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0 and give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0. (Exhibit B-1, Tab 3, p. 56)

Terasen contends that if beta is to be considered a reasonable measure of risk, then the use of the traditional estimate of beta in the CAPM should produce a reasonable estimate of a utility's cost of equity. It calculates that applying conventionally estimated betas for Canadian utilities using the last five years of data in the range 0.25 to 0.30 to a 5-6 percent risk premium on the Canadian market index yields a utility risk premium of 1.5 percent to 1.8 percent. Adding this utility risk premium to the May 2009 forecast yield on long Canada bonds of 3.69 percent produces a cost of equity in the range 5.19 percent to 5.49 percent. Since this result is "absurdly low" in comparison to current yields on utility bonds, Terasen concludes either that: (1) betas as traditionally measured do not correctly measure the risk of utility stocks; or (2) the CAPM does not apply to the Canadian marketplace. (Exhibit B-3, BCUC 14.5.1)

Ms. McShane calculates the "raw" beta for PNG Ltd. ("PNG") to be 0.26 for 2008 (Exhibit B-1, Tab 3, Schedule 11). Dr. Booth testified that PNG was "the riskiest Canadian utility" (T5:603).

JIESC addresses adjustment to beta, noting that Dr. Booth concluded that it is unreasonable to just use the statistical estimate without recognising the underlying events that caused it, and then to make the appropriate adjustments. JIESC submits that Ms. McShane confirmed that no regulatory agency in Canada has accepted adjusted betas and that in the TQM Decision the NEB specifically rejected adjusted betas. (JIESC Argument, p. 37)

Terasen submits that an ROE based on CAPM fails to meet the Commission's obligation to provide Terasen with the opportunity to earn a fair return on its investment in utility assets in that the CAPM methodology does not, and is not intended to, relate to the business risk associated with an investment in utility assets. Rather, it relates to how the investment in one asset (usually a security) affects the overall riskiness of a basket (or portfolio) of investments. CAPM assumes that an investor has a diversified portfolio of investments and that risk is measured only by reference to the impact that a specific investment has on the overall diversified portfolio; CAPM is not attempting to measure the business risk of a utility or other company. (Terasen Argument, para 146)

The May 2003 article from *Public Utilities Fortnightly* cited above states that:

> "CAPM, by comparison, is abstruse as a piece of theory. Further, because most of the components of the calculation are common to all companies (i.e., the risk-free rate and the market risk premium), the CAPM cannot make use of the law of large

> numbers. That is to say, the problems associated with which risk-free rate to pick, or which market risk premium to adopt, hinder the result, no matter how many companies the calculation are performed upon. Finally, the CAPM has no tie to disinterested company analysts that not only reflect, but also shape, the opinions of investors. It is thus no surprise that the CAPM is vastly less popular among US regulatory commissions as a rate of return method." (Exhibit B-20)

JIESC points to page 35 of Dr. Booth's evidence where he states that CAPM is, "overwhelmingly the most important model used by a company in estimating their cost of equity capital," and cites a 2001 survey of 392 US chief financial officers ("CFOs") in the Journal of Financial Economics. Dr. Booth points out that 70 percent of the US CFOs use CAPM and a further 30 percent use a multi-beta approach similar to his two factor model to measure their own cost of equity. (JIESC Argument, pp. 33, 34)

4.1.3 Comparable Earnings Approach

Terasen states that the comparable earnings approach calculates the achieved earnings returns of a sample of low-risk competitive unregulated Canadian firms over a business cycle.

The comparable earnings test is the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The concept that regulation is a surrogate for competition means that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk.

JIESC cites six basic reasons why Dr. Booth does not use a comparable earned rate of return or comparable earnings approach:

- it is an average not a marginal rate of return;
- it is an accounting rate of return not an economic rate of return;
- it may include the impact of market power;
- it is based on non-inflation adjusted numbers;

- it is earned on historic accounting book equity that does not reflect what can be earned on investments today; and
- it varies with the firms selected in the "comparable earnings" sample.

In addition, the JIESC submits that no regulatory board or commission in Canada has given support to the comparable earnings approach in recent years and that the Alberta Energy and Utilities Board ("AEUB") very explicitly rejected its use in its 2004 Generic Cost of Capital Decision (2004-052). (JIESC Argument, pp. 40-41)

At the Oral Phase of Argument, JIESC noted that the AUC had confirmed the AEUB's 2004 finding about CE at paragraph 281 of AUC Decision 2009-216. (T6:774)

Terasen points out that in his evidence, Dr. Booth, as he had in 2005, agreed in that some of his problems with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non inflation-adjusted numbers. (Terasen Argument, para 330)

Terasen submits that the *Act* requires the Commission, "to provide a fair return to the utility and what the utility invests in its infrastructure. It's a fair return to the utility. The *Act* doesn't say it has to be a fair return to the investors in the utility" and notes that the Alberta board rejected CE, "because they said it didn't deal with returns available to investors," which is not the case in BC. (T6:807)

Commission Determination

The Commission Panel has considered the three approaches to determining ROE for a regulated utility and agrees with Terasen that it should take all three into account when establishing an ROE. The Commission Panel agrees that the DCF and ERP are the most common approaches used by regulatory agencies in the US and that CAPM has been widely used in Canada in the period since 1994. The Commission Panel has seen no evidence that suggests: i) it should ignore the fact that the Commission gave the DCF approach weight in the 2006 ROE Decision, or ii) that would persuade it to depart from the Commission's finding in that decision that the CE methodology had not outlived its usefulness when it commented: "However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings."

As for the two most commonly used approaches, the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific. The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been levelled against utility analysts and that *Value Line* estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.

The Commission Panel notes that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.

The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.

Accordingly the Commission Panel determines that in determining a suitable ROE for TGI, it will give most weight to the DCF approach, some lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.

4.2 The Evidence Concerning ROE

This part of Section 4 examines the approaches used by the witnesses to develop their recommended ROEs and the results of the tests they applied.

4.2.1 Discounted Cash Flow

The DCF approach was used by both Ms. McShane and Dr. Vander Weide.

Ms. McShane states that there are multiple versions of the DCF model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

Ms. McShane states that to estimate the DCF cost of equity she used both models and applied the discounted cash flow test to a sample of low risk US "pure-play" electric and gas distributors that were intended to serve as a proxy for TGI. In applying the DCF test, she states she relied solely on published forecast growth rates that were readily available to investors. In applying the constant growth model, she relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations.

To estimate the ROE, Ms. McShane selected a sample of low risk US electric and natural gas distribution utilities, which met the following criteria: were classified by *Value Line* as a gas distributor or an electric utility; had a *Value Line* Safety Rank of "2" or better; had a Standard & Poor's business risk profile of "Excellent" and a debt rating of A- or higher; was not presently being acquired; and had a consistent history of analysts' forecasts.

Thirteen utilities met these criteria of which four (Dominion Resources, Duke Energy, FPL, and Southern Co.) were electric utilities with significant regulated generating assets. (Exhibit B-1, Tab 3, pp. 64-66 and Appendix C)

Ms. McShane agreed that, with the possible exception of Southern Co., such utilities would have to raise considerable amounts of capital replacing their generating assets. (T4:570)

Dr. Vander Weide applied the DCF model to the *Value Line* electric and natural gas utilities which he selected from all the utilities in *Value Line*'s electric and natural gas industry groups that had paid dividends during every quarter and did not decrease dividends during any quarter of the past two years, had at least three analysts included in the I/B/E/S mean growth forecast, were not in the process of being acquired, had a *Value Line* Safety Rank of 1, 2, or 3, and had investment grade S&P bond ratings.

Dr. Vander Weide's selection criteria captured ten natural gas LDCs (a number of which were also featured in Moody's report attached to Exhibit B-6, BCUC 111.1) and 24 *Value Line* electric utilities. The latter included some of the largest generating utilities in the US as well as a number of combination gas and electric utilities. (Exhibit B-1, Tab 4, pp. 33, 60, 61)

Ms. McShane states that her constant growth models indicate a cost of equity of approximately 11 percent. Her two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term (from year six onward) to migrate to the expected nominal long-run growth rate of 5 percent per annum in the economy, and indicates a cost of equity of approximately 10.4 percent (Exhibit B-1, Tab 3, p. 66 and Schedule 18). Ms. McShane updated her constant growth model in Exhibit B-3, BCUC 65.3 and found the result of 11 percent to be "virtually identical."

Dr. Vander Weide concludes that the cost of equity using a constant growth approach is 12.4 percent for the 24 *Value Line* electric utilities in his study and 11.5 percent for the ten *Value Line* natural gas utilities. In response to an Information Request ("IR"), he updated these percentages as of July 2009 to 11.5 percent and 11.9 percent respectively. (Exhibit B-6, BCUC 107.1)

Dr. Vander Weide testified that he did not seek to eliminate utilities which were not "pure-play" natural gas distribution utilities from his study, and that had he done so he might have eliminated Equitable Resources and Questar Corp from his *Value Line* LDCs on the grounds that both companies have significant upstream operations. This would have reduced the cost of equity for his remaining eight "pure-play" *Value Line* LDCs to "something like" 10.5 percent. (T3:388)

JIESC submits that since dividend yields for the period of January 2009 to March 2009 are "biased upwards because stock market prices were at all time lows," the utilization of these yields together with long term I/B/E/S growth forecasts by Ms. McShane will substantially overstate investors' required returns.

Terasen replies that in the response to IR in Exhibit B-3, BCUC 65.3.1, Ms. McShane had updated her results and concluded that the estimated "bare-bones" ROE derived from the constant growth DCF model was virtually identical to the 11.0 percent she had estimated at the time her evidence was filed. (Terasen Reply, para 113)

Terasen discusses the regulatory treatment of US LDCs and of TGI in its Argument. It cites the CEA report for the CGA which states in its Executive Summary: "There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the US."

Terasen submits that the rate setting methodologies of the *Value Line* US LDCs and TGI are quite similar. Both the *Value Line* US LDCs and TGI are subject to rate of return regulations which are designed to provide the companies an opportunity to recover prudently incurred costs and earn a fair rate of return on their investments. In addition, the US LDCs and TGI both benefit from the availability of cost recovery mechanisms that are designed to reduce regulatory lag. (Terasen Argument, para 346-347)

Terasen states that most US gas utilities have automatic rate adjustment mechanisms for purchased gas costs and weather normalization, and that many US gas utilities have decoupling mechanisms that seek to stabilize revenues by "decoupling" gas rates from gas volumes. Decoupling occurs either through a rate design that allows recovery of fixed costs from fixed monthly charges, or through a revenue normalization adjustment mechanism that increases rates or refunds rates to customers for the difference between actual revenues and authorized revenues. (Exhibit B-3, BCUC 74.3)

Terasen identifies another difference in regulatory treatment in that Canadian regulatory agencies do not allow natural gas LDCs to recover deferred income taxes in the rates they charge their customers while US state regulators in the most part do (Exhibit B-11, Panel 1.1). Terasen testified that, at December 2008, TGI had $261 million of income taxes it had not collected from its customers (T3:286).

Dr. Booth states that in 1978 many US utilities faced, "significant regulatory lag that exposed utilities to inflation risk...Subsequently, two factors have largely removed this risk: the decline in inflation and the adoption of forward test years." (Exhibit C11-5, Appendix C, p. 9)

Dr. Vander Weide testified that it was no longer a "rule of thumb" that US regulatory bodies used historic test years to set rates, that there are now many that have forward-looking test years, and that those without forward-looking test periods are able to adjust their historical test periods for known and measurable changes such as commissioning a new plant or a negotiated pay increase settlement. (T3: 391)

Terasen filed the actual earned ROEs of the *Value Line* LDCs which demonstrate that of the eight “pure-play” LDCs (that is ignoring Equitable and Questar), three consistently earned less than their allowed returns and the remaining five earned at or around their allowed ROEs. By excluding Equitable and Questar, the average ROE earned by the 8 remaining *Value Line* LDCs ranged from 10.1 percent to 11.3 percent in the period 2004-2008. (Exhibit B-28)

In its Argument, JIESC quotes Dr. Booth’s evidence that:

> “The regulation of US utilities suffers from the same philosophical and cultural factors in the US and there is no reason to believe that the results are any different. Without examining US regulatory practise in detail, since much of it is the result of individual state regulation, Canadian utilities seem to be regulated on a much more pro-active basis with very little regulatory lag. In contrast, it appears that US utilities sometimes go several years between rate hearings. Canadian utilities also seem to make more use of deferral accounts. As a result, there is little to be gained from looking at US utilities without making significant risk adjustments which is rarely done. However, since the underlying operations are similar and there is increasing uncontested evidence presented on behalf of the utilities, I have started to examine them”. (Exhibit C11-5, Appendix G, p. 2 cited at JIESC Argument, p. 46)

Commission Determination

The Commission Panel agrees that Canadian data do not lend themselves to the DCF approach due to the very limited universe of stand-alone utilities in Canada and the lack of sufficient analysts’ forecasts. However, the Commission Panel has also found that US data can act as a proxy for Canadian data where adequate Canadian data do not exist. Accordingly, the Commission Panel determines that the four DCF tests before it are relevant.

The Commission Panel places no weight to Dr. Vander Weide’s US *Value Line* electric utilities test, since it included a large number of very large US vertically integrated utilities with significant amounts of generation assets. Not only did the inclusion of these very large US vertically integrated utilities tend to skew the results upwards, but they were not in the Commission Panel’s view suitable comparators for a “pure-play” natural gas LDC like TGI.

The Commission Panel gives the most weight to Dr. Vander Weide's *Value Line* natural gas LDC DCF test and to both Ms. McShane's DCF tests. The Commission Panel eliminates the two *Value Line* gas utilities which had significant non-utility operations (Equitable and Questar) from Dr. Vander Weide's test and the four large vertically integrated electric utilities from Ms. McShane's two-stage DCF test. The Commission Panel considers a return in the range of 10.0 percent to 10.5 percent to be a starting point for determining TGI's ROE using the DCF approach.

The Commission Panel agrees with Dr Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short-term, earn its allowed return than the *Value Line* US natural gas LDCs enjoy. The Commission Panel notes Dr. Booth's suggestion that the risk premium required by US utilities is between 90 and 100 basis points more than utilities in Canada require may set an upper limit on the necessary adjustment. Accordingly, the Commission Panel will reduce its DCF estimate by between 50 and 100 basis points to a range of 9.0 percent to 10.0 percent, before any allowance for financing flexibility.

The Commission Panel's determination on the allowance for financing flexibility appears later in this Section.

<u>4.2.3 Equity Risk Premium</u>

Ms. McShane performs three ERP tests: i) a risk-adjusted equity market risk premium test; ii) a DCF-based equity risk premium test; and iii) a historic utility equity risk premium test. (Exhibit B-1, Tab 3, pp. 43-63)

Dr. Vander Weide performs two ERP tests, an *ex post* risk premium and an *ex ante* risk premium test. His *ex post* risk premium test measures the required risk premium on an equity investment in TGI from historical data on the returns experienced by investors in Canadian utility stocks compared to investors in long-term Canada bonds. His *ex ante* risk premium test is based on studies of the expected return on comparable groups of utilities in each month of the study period compared to the interest rate on long-term government bonds. (Exhibit B-1, Tab 4, pp. 30 and 32)

Dr. Booth relies on what he terms a 'classic' CAPM risk premium model and a two-factor model. The 'classic' CAPM estimate is based on an historic average market risk premium "adjusted" for the changing risk profile of the long Canada bond, while his two-factor model takes into account the interest rate sensitivity of utility stocks. As a check to his results he uses a DCF based utility risk premium test. (Exhibit C11-5, p. 56)

The table below summarizes the results of the tests performed:

Witness	**Test**	**Indicated ROE**	**FFA**	**Total ROE**
Ms. McShane	Risk-Adjusted Equity Market Risk Premium Test	8.75%	0.50%	9.25%
	DCF-Based Equity Risk Premium Test	10.00%[1]	0.50%	10.50%
	Historic Utility Equity Risk Premium Test	10.50%	0.50%	11.00%
Dr. Vander Weide	*Ex post* Risk Premium	9.20%	0.50%	9.70%
	Ex ante Risk Premium	11.40%	N/A	11.40%
Dr. Booth	"Classic" CAPM	7.00%	0.75%	7.75%
	Two-stage CAPM	7.00%	0.75%	7.75%

([1]) Revised by Ms. McShane to 9.5 percent. (T4:452)

(Source: Exhibits B-1, Tab 3, p. 63; B-1, Tab 4, p. 35; and C11-5, p. 56)

A comparison of Ms. McShane's risk-adjusted equity market risk premium test and Dr. Booth's "classic" CAPM tests show the following assumptions and results:

	Ms. McShane	Dr. Booth
Long-term Canada bond yield	4.25%	4.50%
Equity risk premium	6.75%	5.00%
Relative risk adjustment	0.65-0.70	0.50
Indicated ROE	8.75%	7.00%
Allowance for financial flexibility	0.50%	0.75%
Total	9.25%	7.75%

Prior to the Oral Phase of Argument, the Commission circulated a letter dated November 18, 2009. The letter had, as an attachment, a document similar to that which Commission staff has prepared each November in accordance with the Commission's Order G-25-94, as amended by Orders G-80-99, G-109-01, and G-14-06 for the purpose of determining the allowed return on common equity for a benchmark low-risk utility for the ensuing year. The document shows that the forecast yield on long-term Canada bonds for 2010 is 4.302 percent. (Exhibit A-12)

4.2.3.1 Ms. McShane's Results

(a) Risk-Adjusted Equity Market Risk Premium Test

For her risk-adjusted equity market risk premium test, Ms. Mc Shane uses a long-term Canada bond yield of 4.25 percent, an equity risk premium of 6.75 percent and a relative risk adjustment of 0.65-0.70 (the relative risk adjustment or beta was described in Section 4.1.2). To derive her equity risk premium of 6.75 percent she used an expected value of the future equity market return in a range of 11.0 percent-12.0 percent, based on both the Canadian and US equity market returns, from which she deducted both the near-term (2010) and the longer-term forecasts for long-term Canada bond yields of 4.25 percent and 5.25 percent respectively. (Exhibit B-1, Tab 3, p. 51)

Terasen submits that because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic and capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data. (Terasen Argument, para 202)

Ms. McShane states that the “raw” calculated betas for the five-year period ending March 2009 of her sample of fifteen US utilities averaged 0.41, while the average reported *Value Line* beta for the sample (and the beta more likely to be relied upon by analysts and investors) was 0.66. (Exhibit B-1, Tab 3, Schedule 15)

Based on her analysis of standard deviations of market returns and betas, Ms. McShane adopts a relative risk adjustment in the range of 0.65-0.70. (Exhibit B-1, Tab 3, p. 57)

JIESC cites Dr. Booth’s evidence in response to Ms. McShane’s evidence: “I don’t believe you can subtract the current LTC [long-term Canada bond] yield from a long run average equity return since it mismatches the underlying inflationary environments…so her procedures may over estimate the market risk premium by at least 1.0%.” (JIESC Argument, p. 36)

JIESC describes Ms. McShane’s adjustment to beta as” unreasonable” and submits that no regulatory agency in Canada has accepted adjusted betas and that in the TQM Decision, the NEB specifically rejected adjusted betas. (JIESC Argument, p. 37)

Terasen replies that Ms. McShane’s relative risk adjustment of 0.65-0.70 is not based on the premise that the utility risk will rise to that of an average risk firm, but rather is based on the following:

- relative standard deviations of utility returns compared to the returns of other sectors of the market composite;
- the empirical evidence generally that the actual returns of low beta stocks have been higher than the theoretical CAPM would predict;

- the empirical evidence specific to Canadian utilities that the actual returns have historically been higher than the "raw" regression betas would predict; and
- the published betas, which incorporate the adjustment toward the market mean of 1.0, and which investors and analysts are likely to rely on when forming their return expectations. (Terasen Reply, para 121)

(b) DCF-Based Equity Risk Premium Test

Ms. McShane performed her DCF-based equity risk premium test by constructing monthly cost of equity estimates for a sample of low risk US gas and electric utilities as a proxy for TGI for the period 1991-March 2009 using the DCF model. Using a single variable and a two variable approach Ms. McShane concludes that the indicated cost for utility equity before any allowance for financing flexibility lay in the 9.7 percent to 10.25 percent range. (Exhibit B-1, Tab 3, pp. 59-61)

In her written evidence, Ms. McShane noted that as of the end of March 2009 the spread between A rated Canadian utility bonds and 30-year Canada bonds was approximately 345 basis points. When preparing her evidence Ms. McShane forecast that spread to decrease to approximately 225 to 250 basis points. In her direct examination at page 452 of the transcript Ms. McShane noted that the spreads had declined more than she had anticipated to a level of approximately 165 to 175 basis points. Using the spread of 170 basis points, she testified that the indicated utility cost of equity before any adjustment for financing flexibility was 9.5 percent (T4:452).

(c) Historic Utility Equity Risk Premium Test

Ms. McShane's historic utility premium test involves comparing the returns of utilities in Canada for the period 1956-2008 and electric utilities and natural gas utilities in the US for the period 1947-2008, on the grounds that, "Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur." An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns and that the utility returns in both the US and Canada have, "clustered in the range of 11.0-12.0%, with a mid-point of approximately 11.5%."

Ms. McShane adopts a long-run forecast of 5.25 percent for long-term Canada bond yields, and deducts that long-run forecast from the mid-point of utility returns (11.5 percent) to derive a utility risk premium of 6.25 percent. To that utility risk premium she adds the 4.25 percent long Canada forecast for 2010 to derive an ROE of 10.5 percent for TGI for 2010. (Exhibit B-1, Tab 3, pp. 62-63)

JIESC submits that Ms. McShane's return recommendation is "excessive and unreasonable." (JIESC Argument, p. 3)

4.2.3.2 Dr. Vander Weide's Results

(a) *Ex post* Risk Premium

Dr. Vander Weide measures the return experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index for the period 1956 -2008; and (2) a basket of Canadian utility stocks created by the BMO Capital Markets ("BMO CM") for the period 1963-2008, which suggests that the former had an equity risk premium of 4.3 percent and the latter 6.6 percent, which Dr. Vander Weide averages and adds the current long bond rate of 3.69 percent to derive an *ex post* risk premium ROE calculation of 9.7 percent.

Dr. Vander Weide states that the BMO CM basket contains Canadian companies that receive a higher percentage of revenues from traditional utility operations than the companies currently in the S&P/TSX utilities stock index, and includes Enbridge Inc. and TransCanada Corporation. (Exhibit B-1, Tab 4, pp. 31-32)

(b) *Ex ante* Risk Premium

Dr. Vander Weide's *ex ante* risk premium test is based on studies of the expected return on comparable groups of utilities in each month of his study period (September 1999 to February

2009) compared to the interest rate on long-term government bonds. The electric utility group yields an *ex ante* risk premium estimate of 8.0 percent, and the natural gas comparable group an *ex ante* risk premium estimate of 7.5 percent. To these percentages he adds the current long-Canada bond yield of 3.69 percent for an average indicated ROE of 11.4 percent. (Exhibit B-1, Tab 4, pp. 32-33)

JIESC submits that the methodology used by Dr. Vander Weide was selective in the period studied and used bond returns rather than bond yields in a period of falling interest rates and thus over estimates utility returns by roughly 3.4 percent. (JIESC Argument, p. 44)

4.2.3.3 Dr. Booth's Results

(a) "Classic" CAPM

Dr. Booth estimates the market risk premium to be 5.0 percent and a uses a beta of 0.50 to develop a utility risk premium of 2.50 percent, to add to his long Canada yield forecast of 4.5 percent to arrive at a required rate of return of 7.0 percent. Adding in 0.50 percent for issue cost and 0.25 percent as a margin for error, he recommends a 7.75 percent fair ROE.

In his written evidence, Dr. Booth states that at the height of the financial crisis, Professor Fernandez surveyed finance professors around the world to find out what they used for the market risk premium. Dr. Booth presented the results of this survey which show that the median in the US is 6.0 percent and in Canada is 5.1 percent. Furthermore, Dr. Booth concluded that "the survey of Fernandez indicated that the 5.8 percent used by the BCUC is within the range of common values used by Canadian Professors of Finance of 5.0% and 6.0 %." (Exhibit C11-5, pp. 50-2)

Terasen submits that the Commission should put no weight on the results of the classic CAPM model of Dr. Booth. (Terasen Argument, para 299)

(b) Two Factor Model CAPM

Dr. Booth estimated a two factor model for utilities where their returns were driven by the common market factor, the TSX Composite return, as well as the return on the long-term Canada bond.

Given the measurement error involved in any statistical estimation and the sensitivity of the estimates to economic conditions, Dr. Booth regards the two models “as being the same.” Terasen submits that Dr. Booth’s application of the two-factor model understates the utility equity return requirement, because it uses a market risk premium which is even lower than that used by Dr. Booth in his classic CAPM approach (5.0 percent vs. 5.5 percent), and ignores other factors which have generated utility returns. This understates the actual utility market returns by close to 20 percent.

Terasen submits that the Commission should put no weight on the results of Dr. Booth’s two-factor model. (Terasen Argument, para 301-305)

(c) DCF Based Utility Risk Premium

As a check for his CAPM results, Dr. Booth uses data for the US electric and gas utilities followed by Standard and Poors to estimate a DCF required rate of return from which he subtracts the ten-year US government bond yield to estimate the utility risk premium for these US utilities at 2.21 percent to 2.68 percent, which he increases to 2.96 percent. He states that if the risk premiums are valid for Canada, they would imply a fair return of 7.50 percent (long Canada yield forecast of 4.50 percent plus the 2.96 percent risk premium) to which the 0.50 percent flotation cost would be added. Although this is slightly higher than his direct estimates from the CAPM and two factor models, he states that it “needs adjusting for the yield gap between ten and 30 year debt yields but indicates that the estimates are in the right ball-park.” (Exhibit C11-5, p. 77)

Terasen points out that Dr. Booth's calculations show: i) negative growth expectations in some instances, and ii) negative calculated utility risk premiums in a significant number of instances. Terasen submits that Dr. Booth's growth rate and resulting utility risk premiums do not reflect investors' expectations. Terasen further submits that the results of Dr. Booth's DCF check, and the utility risk premiums that he estimates using the DCF approach, should be rejected by the Commission. (Terasen Argument, para 311)

Commission Determination

For the ERP approach, the Commission Panel has considered the four "non-CAPM" tests applied by Ms. McShane and Dr. Vander Weide. The Commission Panel considers that both Ms. McShane's DCF-based equity risk premium test and Dr. Vander Weide's *ex ante* risk premium test cover too short a period to be determinative. In addition Ms. McShane computes the risk premium by deducting the current, rather than the experienced, long-term Canada bond forecast from the derived returns. In the Commission Panel's view these two tests can at best be considered checks for the witnesses' DCF tests and the Commission Panel accords them no weight.

The Commission Panel notes that Dr. Vander Weide's *ex post* risk premium test gave 50 percent weight to a BMO CM basket of companies which, in the Commission Panel's view, covered too short a period, contained too few utilities, and included energy holding companies with significant non-regulated operations. Accordingly, the Commission Panel places no weight on this basket.

The Commission Panel considers that the results of Ms. McShane's historic equity risk premium test and Dr. Vander Weide's *ex post* risk premium test yield comparable results on historic Canadian utility data. The Commission Panel finds the Canadian data adequate and, for the reasons set out in its Determination in Section 2 above, gives weight to the Canadian data and no weight to the results of US utility data contained in Ms. McShane's historic equity risk premium test. The Canadian utility data can be summarized as follows:

	Utility Equity Return (%)	Bond Return (%)	Utility Risk Premium (%)
Ms. McShane	12.00	7.80	4.20
Dr. Vander Weide	11.84	7.54	4.30
Average	11.92	7.67	4.25

The Commission Panel considers that the Canadian utility premium of 4.25 percent should be adjusted to reflect the fact that it was calculated over a period when long-term Canada bonds averaged 7.67 percent and that there is not a one-for-one relationship between the increase or decrease in long-term Canada bond yields and the utility equity risk premium. The Commission Panel accepts the evidence of Dr. Vander Weide in this proceeding described in Section 5.0 below that this relationship may range between 0.50 and 0.75 and, using the 2010 forecast long-term Canada bond yield of 4.30 percent in Exhibit A-12, establishes a range of 9.25 percent to 10.25 percent for the ERP approach, before an allowance for financing flexibility.

For the CAPM approach, the Commission Panel has considered Ms. McShane's risk-adjusted equity market risk premium test and Dr. Booth's "classic" CAPM test. The Commission Panel notes that Dr. Booth's two-factor model CAPM test is essentially the same as his "classic" CAPM test and accords it no extra weight. As Dr. Booth's DCF based utility risk premium test was used by him as a check the Commission Panel finds that it need not accord it any additional weight.

The Commission Panel establishes a CAPM estimate by using the Consensus estimate of 4.30 percent for the risk free rate, establishing an equity market premium in the range of the consensus estimate of Canadian professors of finance of 5 percent to 6 percent, and using an adjusted beta in the range of 0.60 to 0.66. This produces a "bare-bones" CAPM estimate in the range of 7.30 percent to 8.30 percent before an allowance for financing flexibility.

4.2.4 Comparable Earnings

Ms. McShane states that her selection of Canadian unregulated companies was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of 490 firms on the TSX in Global Industry Classification Standard sectors 20-30, being Industrials, Consumer Discretionary and Consumer Staples and comprising thirteen major industries.

The initial selection was narrowed down to 27 companies by eliminating companies which:

- had 2007 equity less than $100 million;
- had missing or negative common equity during 1991-2007;
- were income trusts;
- had less than five years of market data;
- paid no dividends in any year 2004-2008;
- traded fewer than 5 percent of their outstanding shares in 2007;
- had stock ranked "higher risk" or "speculative by the Canadian Business Service;
- had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor's, or for which none of the agencies report a rating; or
- had average five-year "raw" betas ending December 2007 and December 2008 in excess of 1.0.

Ms. McShane states that since unregulated companies' returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1991-2007 constitutes a full business cycle including the recession of 1991-1992.

Ms. McShane estimates that the average level of returns for low risk Canadian unregulated companies over a normal business cycle is in the approximate range of 12.5-12.75 percent. The comparative risk data indicate, on balance, that Canadian unregulated companies are somewhat riskier than utilities. The somewhat higher risk of the unregulated companies relative to the typical Canadian utility requires a modest downward adjustment. A downward adjustment of 75-100 basis points (based on the typical spread between Moody's BBB rated long-term industrial bond yields and long-term A rated utility bond yields and the relative betas of the unregulated companies and the Canadian and US utility samples) reduces the ROE to a range of 11.5-11.75 percent.

Ms. McShane states that although she considers that the arguments that a downward adjustment to the comparable earnings test results for market/book ratios are without merit, the data indicate that the market/book ratio for the overall Canadian equity market averaged approximately 2.0 times from 1991-2007, the period over which the comparable earnings test was conducted, while the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times. In her view, the similarity of the lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian equity market composites permits the inference that the sample average returns are not characterized by market power. Thus, she submits the comparable earnings results do not warrant an adjustment for market/book ratios.

Ms. McShane also does a comparable earnings test on a larger sample of US unregulated companies which suggests a higher return on equity. (Exhibit B-1, Tab 3, pp. 67-72)

Commission Determination

As for the CE approach, the Commission Panel has reviewed Ms. Mc Shane's selection process, the period of the study, and the results. The companies display conservative stock and debt ratings, an average market to book ratio of 2.1, and an average adjusted beta of 0.71. The Commission Panel considers that the initial results of 12.5 percent which Ms. McShane reduced to 11.5 percent suggest that an estimate of what unregulated Canadian companies of low business risk are earning on the book values of their equity may lie in the range of 10.5 percent to 11.5 percent.

4.2.5 Allowance for Financing Flexibility

Ms. McShane states that a financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. It is intended to cover three distinct aspects:

- flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity;
- a margin, or cushion, for unanticipated capital market conditions; and
- recognition of the "fairness" principle.

Ms. McShane contends that, at a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10, where a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard. (Exhibit B-1, Tab 3, pp. 66-67)

Terasen states that the application of a return estimated on the basis of market values and applied to book values implies a market value just equal to book value, and drew the Commission's attention to the conclusion drawn by Alberta's Independent Assessment Team in its review of the cost of capital for the Power Purchase Arrangements in 1999, where it stated: "This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada." TGI states that the adjustment to the market derived cost for financing flexibility rate provides a minimal increment to preserve financial integrity (i.e. market price slightly in excess of book value). (Exhibit B-3, BCUC 64.1)

Both Ms. McShane and Dr. Vander Weide propose the addition of an allowance for financing flexibility of 50 basis points to what they term the return on equity estimates derived from their DCF and equity risk premium tests, although Dr. Vander Weide does not propose to add it to his *ex ante* risk premium test.

Dr. Vander Weide testified that in the DCF model an issue discount of 2-3 percent on a utility's stock price coupled with issue costs of 5 percent "would amount to approximately 25 basis points." (T3:393)

Similarly Dr. Booth adds an allowance for issue costs of 50 basis points and 25 basis points as a "margin of error." Dr. Booth states: "However, I normally add 50 basis points as a cushion to the direct estimates in line with this practice of many regulators. This is mainly to ensure that there is no dilution and stock prices are more variable than a 10 percent floatation cost allowance would indicate." (Exhibit C11-5, p. 60)

The AUC adjusts CAPM results by adding 50 basis points to CAPM estimates on the grounds that "CAPM results likely underestimate the required market equity return by at least 50 basis points." (AUC Decision 2009-216, para 326)

Commission Determination

The Commission Panel finds no evidence before it to suggest that utilities in Canada trade in the market/book range of 1.05 to 1.10 that prompts Ms. McShane's recommended 50 basis point allowance for flotation costs. The Commission Panel agrees with Dr. Vander Weide that under normal circumstances flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity, require a 25 basis point addition to a ROE estimate.

The Commission Panel notes that the margin, or cushion, for unanticipated capital market conditions was used in Alberta in a situation where a formula for 20 year Power Purchase Arrangements was being established. It does not find the reference relevant in this proceeding.

As for the fairness principle, the Commission Panel agrees with the practice of the AUC of adding 50 basis points to CAPM estimates and adopts it in this proceeding.

Accordingly the Commission Panel determines that for DCF, ERP and CAPM estimates it will add a 25 basis point allowance to recognize the cost of issuing additional equity. The Commission Panel will add an additional 50 basis point fairness allowance to CAPM estimates. The Commission Panel will make no allowance for CE estimates.

4.2.6 Fair Return on Equity

Having determined that it will accord weight to each of the three approaches and determined the appropriate ROE ranges that the approaches yielded, the Commission Panel can determine TGI's ROE.

Commission Determination

Earlier in this Decision the Commission Panel found that the suitable equity ratio for TGI is in the 40 percent range, and that it would consider the effect of its short-term business risk mitigators (such as RSAM and deferral accounts) in the determination of TGI's ROE.

The Commission Panel also determined that it would give most weight to the DCF approach, lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.

The following table sets out the Commission Panel's determined ranges for each approach:

Approach	Range (%)	Allowance (%)	Total (%)
DCF	9.00-10.00	0.25	9.25-10.25
ERP	9.25-10.00	0.25	9.50-10.25
CAPM	7.30-8.30	0.75	8.05-9.05
CE	10.5-11.5	0.0	10.5-11.5

Accordingly, after attaching the weight that it considers appropriate to each of the three approaches the Commission Panel determines that the ROE for TGI is 9.50 percent.

4.3 Interim Rates and the Effective Date of the ROE Increase

Terasen requests that any increase in the ROE of the three utilities should be reflected in their rates effective from July 1, 2009. Prior to the commencement of the Oral Hearing, the Commission Panel considered an application by Terasen pursuant to section 89 of the *Act*, that the rates of the three utilities be made interim effective July 1, 2009. Section 89 of the *Act* is included in Appendix C to the Decision.

All Intervenors opposed Terasen's request at that time. The CEC submitted that all parties had agreement on the equity ratio and the ROE in the Commission approved settlement documents that can be found in Commission Order G-33-07. CEC acknowledged that while the 2008/2009 Negotiated Settlement Agreement ("NSA") did not preclude Terasen from applying to the Commission for a variation in its equity ratio or ROE, it submitted that it was inequitable that Terasen would seek and receive an adjustment for a period of six months of the 2008/2009 settlement period on what it termed a retroactive basis. (Exhibit C3-2)

Terasen's Reply pointed out that its request was in no way retroactive and that it was perfectly within the terms of the NSA. (Exhibit B-2)

In Order G-78-09 dated June 24, 2009, the Commission Panel agreed with Terasen Utilities that an Order approving the requested relief that their current rates be made interim would be on a 'without prejudice' basis, and that "all Parties will have the opportunity to fully participate in the hearing process and no final order will be made until all evidence has been heard and considered." (Exhibit A-4)

In its Reply, Terasen notes that no Intervenor disputed that the change to the ROE of Terasen should be effective July 1, 2009 (Terasen Reply, para 1). During the Oral Argument Phase counsel for JIESC, CEC ICG and BCOAPO all stated that they took no position on the issue (T6:837).

Commission Determination

The Commission Panel notes that the Intervenors take no position on this issue and grants the relief requested by Terasen. The effect of this determination will result in the ROE for TGI for 2009 being 8.47 percent for 6 months and 9.50 percent for six months or an average annual ROE of 8.98 percent, with that of TGVI being on average 60 basis points higher for 2009 (in accordance with the Commission Panel's determination at Section 6.1 below) and that of TGW 50 basis points higher for 2009.

4.4 The Impact of the Determinations on the Fair Return Standard

Having established an equity ratio of 40 percent, and a ROE of 9.5 percent , the Commission Panel revisits the fair return standard to ensure that TGI's overall return will be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement), enable TGI's financial integrity to be maintained (financial integrity requirement), and permit TGI to attract incremental capital on reasonable terms and conditions (capital attraction requirement).

In this regard it has considered Moody's credit metrics and its rating of TGI.

The Commission Panel notes that the ROE of 9.5 percent should enable TGI, following the end of its PBR regime, to maintain its earnings in the 9.0 to 14.0 percent range and maintain this metric at its present level in Moody's A range.

The Commission Panel considers that the combination of a 40 percent equity level and a ROE of 9.5 percent will improve the financial metrics such as EBIT/Interest, Retained Cash Flow/Debt, Debt to Book Capitalization and Free Cash Flow/Funds from Operations.

The Commission Panel observes that a 40 percent equity level would move TGI from a Ba to Baa under Moody's factor mapping and that this metric alone is worth 15 percent of a Moody's rating. Similarly the combination of a 40 percent equity level and a ROE of 9.5 percent will result in an increase in EBIT/Interest from between 1-2 to between 2-3 and would move TGI from Ba to Baa, under Moody's factor mapping and that this metric is worth another 15 percent of a Moody's rating.

These improvements in metrics should, in the Commission Panel's opinion, enable TGI both to maintain its A3 rating with a margin of comfort and to attract the capital it requires on reasonable terms and conditions.

In addition, the Commission Panel considers that the combination of a 40 percent equity level and a ROE of 9.5 percent will increase TGI's times interest covered ratio and will thus enable it to raise comfortably more than the $100 million of unsecured debentures its current equity level and ROE allow.

As a result the Commission Panel considers that its decision meets the fair return standard for TGI.

5.0 THE AUTOMATIC ADJUSTMENT MECHANISM

This Section addresses the issues:

- Given TGI's appropriate ROE, does the Commission's adjustment mechanism produce an ROE that meets the fair return standard?
- If not, should the Commission retain, amend, or eliminate the adjustment mechanism?

Terasen requests that the adjustment mechanism be eliminated, with all three of its expert witnesses urging the Commission to abandon the formula.

Ms. McShane states that reliance on a formula which tracks changes in the long-term Canada bond yield, rather than the composite of factors that bear on equity return requirements, has resulted in allowed ROEs falling below levels commensurate with a fair return and that the extent to which this has happened since 1994 can be assessed by the table which compares the allowed ROEs of Canadian and US utilities set out in Section 2.3 of this Decision.

Terasen submits that the adoption of adjustment mechanism in Canada in the mid-1990s coincided with the almost exclusive use of equity risk premium and CAPM approaches for the determination of allowed ROE for utilities in Canada.

Ms. McShane testified that the crossover between Canadian and US utility returns started when regulatory commissions in Canada started to place almost all the weight on the CAPM and equity risk premium tests. (T4:565)

Terasen states that since the adjustment mechanisms were first adopted in the mid 1990s, yields on long-term Canada bonds have steadily decreased and returns on equity allowed for Canadian utilities have decreased to unprecedented low levels.

In addition the turbulence in the capital markets experienced in the last three years has led to a "flight to quality" which has created an abnormal demand for long-term Canada bonds that were already in short supply. This flight to quality has driven down the yield on the long-term Canada bonds, and consequently driven down the formulaic ROE that uses the long-term Canada bonds as a benchmark. Yet even as the allowed ROE has declined, the cost of capital for utilities has risen dramatically, as investors have demanded higher premiums for risk.

Terasen contends that if it cannot offer a return to equity to investors similar to returns available to comparable risk investments, it will be disadvantaged in competing for capital in the future, even if the capital markets return to historical norms. (Exhibit B-1, p. 23)

Mr. Carmichael points to credit rating agencies which have recently highlighted their concerns regarding the weak state of credit metrics achieved by utilities such as TGI that are regulated with an ROE formula, and which have compared such utility's lower metrics with those of US utilities that the rating agencies believe to be comparable.

Mr. Carmichael states that the financial performance of utilities in Canada lags the performance of US based utilities. This has prompted an equity analyst to suggest that ROE formulae in use by regulators in Canada are "confiscatory and fail to meet the fair return standard," while other analysts suggest that the formulae are now "broken." According to the latter group of analysts, under current financial market circumstances such formulas result in lower rates of return on common equity, while all evidence indicates that capital markets require higher returns on corporate securities reflecting the re-pricing of risk which has taken place. Debt analysts have opined that ROE results produced by the formulas "have not reflected the real world increase in the cost of capital" and "the annual ROE adjustment is not even yielding the right direction of change in the cost of capital." (Exhibit B-1, Tab 2, p. 7)

Dr. Vander Weide performs a number of tests to determine the validity of the adjustment mechanism ROE formula, the most significant of which were to examine evidence on the sensitivity of the forward looking, or *ex ante*, required equity risk premium on utility stocks to changes in interest rates in Canada and the US. He states that while the ROE adjustment formula implies that the cost of equity for TGI declines by 75 basis points for every 100-basis-point decline in the yield to maturity on long-Canada bonds, his findings support the conclusions that i) the cost of equity declines by less than 50 basis points for every 100-basis-point decline in the yield to maturity on long-Canada bonds, and ii) US regulators typically reduce the allowed ROE by less than 50 basis points when the yield to maturity on long-term government bonds declines by 100 basis points. (Exhibit B-1, Tab 4, p. 9)

According to Terasen the process of designing an automatic adjustment formula should involve a balance among the following criteria:

- it should be relatively simple to understand and apply;
- it should be based on changes in one or more reasonably available and verifiable variables;
- it should exclude changes in variables due to abnormal market events;
- it should incorporate variables which vary in a quantifiable way with the utility cost of equity; and
- it should incorporate variables which are not vulnerable to changes caused by company-specific circumstances which may not impact on the cost of equity for the utilities to which the formula applies. (Exhibit B-1, pp. 31-32)

Terasen stated that it was working on the design of such a formula, but had nothing to show for its efforts so far. (T2:87-88)

FortisBC supports Terasen's Application, including the elimination of the AAM. (FortisBC Argument, para 2)

PNG submits that, "the evidence in this proceeding demonstrates overwhelmingly that the automatic adjustment formula does not produce a fair return on common equity for BC utilities and should therefore be eliminated, at least until a more appropriate automatic adjustment mechanism can be determined." (PNG Argument, para 4)

On the other hand, Dr. Booth states that, "…I would recommend that the BCUC maintain their ROE formula indefinitely since like most such formulae in Canada it has done a remarkably good job of awarding ROEs that are within a zone of reasonableness, while minimising repetitive testimony. It is also broadly consistent with awarding allowed ROEs consistent with adjustment formulae used elsewhere in Canada." (Exhibit C11-5, pp. 3, 4)

JIESC submits that Terasen's analysis comparing US with Canadians ROEs is "oversimplified and incorrect. All of the data shows that risk premiums generally, not just for utilities, for Canada are lower that (sic) in the US. ...Canadian and US Utility and market risk premiums departed company, not when the AAM came into place, but when Canada got its financial house in order in 1997 and the US failed to do so. Up until last year Canada generally had financial surpluses and the US has faced increasing deficits." (JIESC Argument, p. 45)

Terasen observes that while in 1995 the NEB adopted an AAM similar to that adopted in BC in 1994, that in the NEB Letter Decision, the NEB determined that the RH-2-94 Decision will not continue in effect. As a result, the return on equity for the pipelines regulated by the NEB will not be determined by an automatic adjustment mechanism (Terasen Argument, para 4).

At the Oral Phase of Argument, counsel for FortisBC pointed out that the AUC had "moved away from" its automatic adjustment formula in AUC Decision 2009-216. (T6:743)

Commission Determination

A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.

The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.

In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI for 2010, it would seem inconsistent to retain the adjustment mechanism.

Accordingly the Commission Panel directs that the AAM be eliminated. TGI is directed to complete its study of alternative formulae and report to the Commission by December 31, 2010.

6.0 THE APPROPRIATE RETURN ON EQUITY FOR TGVI AND TGW

This Section looks at TGVI and TGW. The business risks of each are considered and a suitable capital structure and ROE for each are determined. It addresses the issue: Given TGI's appropriate capital structure and ROE what are the appropriate ROEs for TGVI and TGW?

TGVI and TGW request that the Commission continue to set their respective allowed returns on equity with reference to the Benchmark ROE established in this proceeding for TGI by adding a utility specific premium of 70 basis points for TGVI and 50 basis points for TGW to the Benchmark ROE.

Terasen submits that the business risks relating to TGI also relate to TGVI and TGW. All three companies are in the natural gas distribution business in British Columbia, and all three are subject to the provincial policies and legislation, and other factors that have increased the risk of TGI.

6.1 TGVI

TGVI requests that the Commission continue to set it's allowed ROE with reference to TGI's ROE established in the proceeding by adding a utility specific risk premium of 70 basis points to TGI's ROE.

In addition to TGI's business risk Terasen cites additional sources of business risk faced by TGVI:

- TGVI is a relatively immature LDC seeking to build a new market on Vancouver Island where it is at a competitive disadvantage caused by the differences in gas versus electric rate design methodologies;
- TGVI is burdened with the recovery of an accumulated deficit that peaked at approximately $88 million in 2002;
- TGVI faces the elimination of Provincial royalty revenues in 2012 that have ranged from $35 to $40 million in recent years and cover approximately 20 percent of the current cost of service;

- TGVI is highly dependent on industrial load related to the Vancouver Island Pulp Mill Joint Venture which is taking transportation service at its minimum allowed levels and whose contracts expire at the end of 2012, and the Island Cogeneration Project ("ICP") contract with BC Hydro whose future has been made less certain by the current climate change legislation and policy;
- TGVI faces a greater security of supply risk due the fact that all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities; and
- TGVI will become liable to repay $75 million of non-interest-bearing senior government debt, currently sitting as a credit to rate base, which when repaid will contribute to higher cost of service and impact the competitive position of the utility.

Terasen cites Ms. McShane's testimony in the 2005 ROE hearing as follows:

> "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return." (Exhibit B-11, Panel 1.6)

In the 2006 ROE Decision, the Commission found: "that the uncertainty surrounding the contract with BC Hydro beyond 2007 creates a significant incremental change to TGVI's business risk together with uncertainty as to the ultimate recovery of the balance on the RDDA. In addition, the uncertainty regarding the cessation of royalty payments from the Provincial Government and the need to repay the interest free loans from senior levels of government demonstrate that TGVI is exposed to considerably greater business risk than a benchmark low-risk utility. It is evident to the Commission Panel that in TGVI's case the probability of not earning a return on and of capital is considerably higher than is the case with the five "mature" gas distribution companies in Canada" (2006 ROE Decision, page 30). Based on these findings the Commission approved an equity ratio of 40 percent for TGVI and ROE 70 basis points higher than TGI.

6.2 TGW

TGW requests that the Commission continue to set its respective allowed ROE with reference to TGI's ROE established in the proceeding by adding a utility specific risk premium of 50 basis points to TGI's ROE.

Terasen submits that the relative risk of TGW as compared to TGI since the proceeding that led to the Commission's Order G-35-09 in April 2009, which found that a premium of 50 basis points over the Benchmark ROE was appropriate, has not changed. (TGI Argument, para 364)

Commission Determination

The Commission has in the past awarded both increased equity ratios and ROEs for both TGVI and TGW over those awarded TGI. The Commission Panel considers that TGVI's risk has declined since 2005 because of i) the resolution of the contract with BC Hydro at ICP and ii) greater certainty around the recovery of its RDDA balance.

Accordingly the Commission Panel determines that TGVI's premium over TGI's ROE should be reduced from 70 basis points to 50 basis points. The Commission Panel determines that TGW's premium over TGI's ROE should remain at 50 basis points for the reasons set out in the Commission Order G-35-09.

The Commission Panel notes that in determining TGI's equity ratio and ROE in this proceeding it has sought to determine an equity ratio for TGI that reflects its long-term business risks, while adjusting its ROE to reflect its short-term business risks. It also notes that the evidence suggests that both TGVI and TGW have greater long-term business risk than TGI while possessing similar deferral mechanisms to enable them to earn their allowed ROEs in the short-term. The Commission Panel further notes Ms. McShane's testimony that both utilities require greater equity thickness than 40 percent.

Accordingly, the Commission directs TGVI and TGW to file with their next revenue requirement applications evidence as to what equity component best reflects their respective long-term business risks.

7.0 TGI AS THE BENCHMARK UTILITY

This Section discusses the concept of the benchmark utility and what effect the Commission Panel's determination should have on other utilities in BC primarily FortisBC and PNG. It addresses the issue: What impact should the Commission Panel's determination have on the remaining utilities in BC that may be affected, namely FortisBC and PNG.

Ms. McShane observes that, "it is important to recognize that, while it may be administratively efficient to designate one utility as the "benchmark," it does not necessarily follow that (1) the designated benchmark is the lowest risk utility, or (2) that the risk of the designated benchmark utility does not change over time relative to its peers." (Exhibit B-1, Tab 3, p. 24)

In response to an Information Request as to whether TGI still considered itself a "benchmark low-risk utility" for the purposes of setting allowed ROEs, TGI replies that it has been designated "a benchmark low-risk utility" by the Commission, and points out that BC Hydro and BC Transmission Corporation have their ROE set with reference to the most comparable investor owned utility, which by virtue of size and geography has defaulted to TGI.

TGI accepts that it is has been, and will be, the benchmark utility in respect of being the "benchmark" or "standard" used to set the ROE of other utilities in BC, but does not consider itself to be "a benchmark low-risk utility" now, if it ever was. Any utility could act as the benchmark and TGI due to its size has been selected as the benchmark by the Commission in the past. (Exhibit B-3, BCUC 2.1)

PNG submits that if the Commission determines that the AAM no longer produces a fair return for the Terasen, it follows that the formula no longer produces a fair return for the other utilities subject to the formula, including PNG.

PNG states that it will assess whether any adjustment to its utility specific risk premiums are required as a result of the Commission's decision and, if adjustments are required, that it will file an update to its 2010 Capital Structure and Equity Risk Premium Application. (PNG Argument, para 3)

FortisBC seeks an order of the Commission maintaining the current regulatory framework in British Columbia whereby TGI's ROE is established as the Benchmark ROE for utilities in British Columbia, including FortisBC, as previously ordered by the Commission in Order G-14-06.

FortisBC submits that the Commission determined in 1994 that the use of a benchmark was in the public interest, and that there is no evidence in the record of this proceeding to suggest that the benchmark concept should be abandoned in British Columbia. FortisBC identifies a number of advantages that flow from a Benchmark ROE for utilities including:

- cost savings to the Commission and to Intervenors in avoiding additional, unnecessary hearings; the evidence related to economic outlook and capital market conditions need not be presented nor heard more than once;
- a consistent approach to economic outlook and capital market conditions, considered with reference to expert evidence gathered at a single point in time; and
- greater consistency with respect to ROE determinations for individual utilities from a common base.

FortisBC submits that the NSA approved by the Commission in Order G-193-08 is a performance based regulation settlement and contemplates the application of the TGI's ROE as the Benchmark ROE for FortisBC through to, at a minimum, 2011. The NSA provides for FortisBC to receive the "allowed return on equity" which is calculated by reference to the Benchmark ROE with adjustments and sharing as contemplated in the approved NSA.

Commission Determination

The Commission Panel notes that PNG seeks no relief in this proceeding and that it proposes to consider this Decision and to determine if any amendments to its 2010 Capital Structure and Equity Risk Premium Application are merited.

The Commission Panel agrees with FortisBC that there is no evidence on the record in this proceeding suggesting that the use of a Benchmark ROE is not in the public interest. **Accordingly the Commission Panel determines that the ROE for TGI it has determined in this proceeding should continue to serve as the Benchmark ROE for FortisBC and any other utility in BC that uses the Benchmark ROE to set rates.**

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of December 2009.

Original signed by:
A.J. (TONY) PULLMAN
PANEL CHAIR/COMMISSIONER

Original signed by:
DENNIS A. COTE
COMMISSIONER

Original signed by:
MICHAEL R. HARLE
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-158-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by
Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and
Terasen Gas (Whistler) Inc. ("TGW") (collectively the "Terasen Utilities")
for Return on Equity and Capital Structure

BEFORE: A.J. Pullman, Panel Chair
D.A. Cote, Commissioner
M.R. Harle, Commissioner

December 16, 2009

O R D E R

WHEREAS:

A. By letter dated May 15, 2009, the Terasen Utilities filed with the British Columbia Utilities Commission (the "Commission") pursuant to sections 59 and 60 of the *Utilities Commission Act* (the "*Act*"), an application for Return on Equity and Capital Structure (the "Application"); and

B. TGI applied for an increased Return on Equity ("ROE") for rate-setting purposes, and that the so determined ROE for TGI be used in establishing the ROE of TGVI and TGW used for rate-setting. The Application requests that the revised ROE be effective from July 1, 2009. In addition TGI applied for an increase of the equity ratio in its Capital Structure to 40 percent effective January 1, 2010. Terasen Utilities further requested that the Commission set their current rates as interim, effective July 1, 2009, until such time as permanent rates were established; and

C. By Order G-53-09 dated May 21, 2009, the Commission established a Procedural Conference to take place on June 9, 2009 to hear submissions regarding the regulatory process for the review of the Application; and

D. Further to the Procedural Conference, the Commission issued Order G-70-09 dated June 9, 2009 which established a Regulatory Timetable for an Oral Hearing Process as well as a schedule for written argument to hear submissions from the Parties on the subject of the request for interim rates; and

E. By Order G-78-09 dated June 24, 2009, the Commission ordered, with Reasons for Decision attached as Appendix A to the Order, that the current rates of TGI and TGW be set as interim effective July 1, 2009 and that the changes to the allowed ROE from this proceeding be treated as changes to TGVI's cost of service, effective July 1, 2009; and

F. The Oral Hearing took place from September 28, 2009 to October 1, 2009. The following Intervenors took an active role in the proceedings, filed written argument or took part in the Oral Phase of Argument; the British Columbia Old Age Pensioners' Organization *et al.* ("BCOAPO"), the Commercial Energy Consumers of British Columbia ("CEC"), FortisBC Inc. ("FortisBC"), Pacific Natural Gas Ltd. ("PNG"), the Joint Industry Electricity Steering Committee ("JIESC") and the Industrial Customer Group ("ICG"); and

G. The schedule of written Argument provided for Final Submissions to be filed as follows: i) Terasen Utilities, FortisBC and PNG on or before October 20, 2009; ii) Intervenors on or before November 6, 2009; and iii) Reply from Terasen Utilities, FortisBC and PNG on or before November 13, 2009; and

H. An Oral Phase of Argument was held on November 24, 2009; and

I. The Commission Panel has considered the Application, the evidence, and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The appropriate equity ratio for TGI is 40 percent effective January 1, 2010.

2. TGI is to file within 30 days a document setting out how and when it will implement the change to its capital structure in compliance with the ring-fencing conditions approved by Commission Order G-49-07.

3. A return on equity for TGI of 9.50 percent for rate-setting purposes is approved effective July 1, 2009.

4. The TGI ROE approved in paragraph 3 of this Order is to be used as the Benchmark ROE in establishing the return on equity of TGVI and TGW used for rate-setting purposes and the allowed return on equity for TGVI and TGW is effective July 1, 2009.

5. TGVI's request to continue to set its allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 70 basis points is denied. TGVI is allowed a utility specific risk premium of 50 basis points above the Benchmark ROE.

6. TGW's request to continue to set its allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 50 basis points is approved.

7. TGVI and TGW are to file in their respective next revenue requirement applications evidence on the equity component that best reflects their respective long-term business risks.

8. The TGI ROE approved in paragraph 3 of this Order can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates.

9. The automatic adjustment mechanism is eliminated.

10. TGI is to complete its study of alternative formulae to an automatic adjustment mechanism and report to the Commission on the study results by December 31, 2010.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of December, 2009

BY ORDER

Original signed by:

A.J. Pullman
Panel Chair and Commissioner

THE APPLICATION

On May 15, 2009 Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI"), and Terasen Gas Whistler Inc. ("TGW") filed a return on equity and capital structure application under sections 59 and 60 of the *Utilities Commission Act* with the British Columbia Utilities Commission ("Application").

The following Intervenors took an active role in the proceedings, filed written argument or took part in the Oral Argument Phase of the proceedings:

- Joint Industry Electricity Steering Committee ("JIESC")
- Commercial Energy Consumers of BC ("CEC")
- British Columbia Old Age Pensioners Organization

  Active Support Against Poverty
  B.C. Coalition of People with Disabilities
  Council of Seniors' Organizations of B.C.
  End Legislated Poverty
  Federated Anti-Poverty Groups of B.C., and
  Tenants' Rights Action Coalition (collectively "BCOAPO")

- Industrial Customer Group, comprising:

  Certainteed Gypsum Canada Inc.
  Domtar Pulp and Paper Products Inc.
  Federated Co-operatives Ltd.
  Teck Metals Ltd., Weyerhaeuser Company Ltd. and
  Zellstoff Celgar Limited Partnership (collectively"ICG")

- FortisBC Inc.
- Pacific Northern Gas Ltd.

Following receipt of the Application, the Commission issued Order G-53-09 dated May 21, 2009 establishing a Preliminary Regulatory Timetable, including a notice of procedural conference to be held on June 9, 2009.

By Order G-70-09 dated June 9, 2009 following the procedural conference, the Commission published the final Regulatory Timetable which set dates for two rounds of Information Requests and an Oral Hearing to commence on September 28, 2009.

Order G-70-09 also established a schedule for written argument on the subject of Terasen's request pursuant to section 89 of the *Act* for interim rates. Intervenor submissions were due on June 15, 2009 and Terasen reply by June 22nd, 2009.

By Order G-78-09 and Reasons for Decision dated June 24, 2009, the Commission approved, pursuant to section 89 of the *Act*, of the request of TGI and TGW that their respective current rates be set as interim, effective July 1, 2009. In addition, pursuant to the provisions of the Special Direction made under section 7 of the Vancouver Island Natural Gas Pipeline Act, the Commission ordered that changes to the allowed ROE from the proceeding were to be treated as changes to TGVI's cost of service, effective July 1, 2009.

The Commission Panel accepted Terasen's submission that the application for interim relief should be reviewed pursuant to section 89 of the *Act* which does not refer to special circumstances. It further agreed with Terasen that a Commission Order approving the requested relief that the current rates be made interim was on a 'without prejudice' basis, that all parties would have the opportunity to fully participate in the hearing process and that no final order would be made until all evidence had been heard and considered. (Exhibit A-4)

The Oral Hearing commenced on September 28, 2009 and concluded on October 1, 2009. Argument was received from the Terasen, PNG and FortisBC on October 20, 2009. Argument was filed by the following Intervenors on November 6, 2009: JIESC, BCOAPO, CEC and ICG. Reply was filed by Terasen on November 13, 2009.

The Oral Phase of Argument was scheduled to take place on November 24, 2009. Parties were originally asked to address the following issues:

- Whether the Commission Panel can take into account the Alberta Utilities Commission 2009 Generic Cost of Capital Decision, Decision 2009-216, dated November 12, 2009 (Decision 2009-216) in arriving at its decision?
- Whether the Commission Panel should take into account Decision 2009-216 in arriving at its decision?
- If the Commission Panel were to eliminate the automatic adjustment mechanism ("adjustment mechanism") as requested by the Terasen Utilities, upon what evidentiary basis can the Commission Panel conclude that the return on common equity ("ROE") that it determines for TGI in this proceeding should be used as the benchmark or generic ROE for FortisBC and Pacific Northern Gas?
- If the Commission Panel were to eliminate the adjustment mechanism as requested by the Terasen Utilities and conclude that the ROE that it determines for TGI in this proceeding should not be used as the benchmark or generic ROE for FortisBC and Pacific Northern Gas, what are the consequences for FortisBC and Pacific Northern Gas?

By letter dated November 18, 2009 the Commission added two additional issues to the Agenda and requested that parties address a document prepared by Commission staff in accordance with the Commission's Order G-25-94, as amended by Orders G-80-99, G-109-01, and G-14-06 for the purpose of determining the allowed return on common equity for a benchmark low-risk utility for the ensuing year, which showed that the current formula resulted in an allowed return on common equity of 8.43 percent for a low-risk benchmark utility in 2010. The two further issues to be addressed were:

- Whether any party objects to the Commission Panel relying upon the staff document in arriving at its decision; and
- If there is no objection, now that the formula has produced an allowed return on common equity for 2010 of 8.43 percent, does it follow that, for the purposes of the JIESC Final Argument, the Panel no longer needs to consider the JIESC alternative position to set the return on equity on the basis of Dr. Booth's recommendation of 7.75 percent?

The Oral Phase of Argument took place on November 24, 2009 as scheduled.

THE HISTORY OF ROE AWARDS IN BC, CANADA AND THE US SINCE 1994, AND THE USE OF A FORMULA TO ESTABLISH ROE

Prior to 1994 the ROE and capital structures of utilities in North America for rate setting purposes were established as part of the periodic revenue requirement applications the utilities would file with their regulators. In 1994, the BCUC held a public hearing into the appropriate rates of return on common equity and capital structure for BC Gas (now TGI), West Kootenay Power (now FortisBC) and PNG. In addition, the Commission heard evidence on processes or mechanisms that might be employed to improve the determination of ROE and capital structures in future years. In its decision dated June 10, 1994 attached to Order G-35-94, the Commission, for the purpose of setting the 1995 rate of return on common equity for utilities subject to its jurisdiction, accepted an automatic adjustment mechanism, based on long-term Canada bond yields. The formula has remained in place since that time and was adjusted by Orders G-80-99 and G-109-01. Following the 2005 ROE hearing the Commission issued Order G-14-06 and its 2006 ROE Decision on March 2, 2006, amending the formula.

As a result of Order G-14-06 the benchmark ROE now rises or falls by 75 basis points for each 100 basis point increase or decrease in the forecast long-Canada bond yield, as follows: ROEt = 9.145% - [0.75 x (5.25% - YLDt)], where YLDt equals the forecast long-term Government of Canada bond.

By Letter L-55-08 dated November 20, 2008, the Commission determined that the current ROE automatic adjustment mechanism resulted in an allowed return on common equity of 8.47 percent for a low-risk benchmark utility in 2009. This was calculated by averaging the November 2008 Consensus Forecasts of the 10-year Canada bond yield at the end of [both?] February and of November, 2009, and adding the average yield spread between 10-year and 30-year bonds of 0.50 percent reported by the Bank of Canada for all trading days in October, 2008 to arrive at the forecast yield on long-term Canada bonds for 2009 of 4.35 percent.

Commission Order G-14-06 set the approved benchmark return on equity (ROE) at 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent, and directed that where the forecast yield was greater or less than 5.25 percent, a sliding scale adjustment would raise or lower the benchmark ROE by 75 percent of the change in the forecast yield on long-term Canada bonds which would be rounded to the nearest 2 decimal places as follows:

$$9.145 - (0.75 * (5.25 - 4.35)) = 8.470\%$$

Based on L-55-08 the following ROEs were approved for 2009 for the following utilities in BC on their capital structures: Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Fortis BC Inc. and Pacific Northern Gas Ltd.

Section 4(d) of Special Direction No. HC2 obliges the Commission to set rates for BC Hydro that enable it to achieve an annual rate of return on equity equal to the pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Act.*

Similarly, section 3(c) of Special Direction No. 9 obliges the Commission to set rates for BCTC that generate for the transmission corporation an annual rate of return on deemed equity that is equal to the annual rate of return that is allowed by the commission on the authority's equity as that term is defined in Special Direction HC2.

In Canada an adjustment mechanism was employed by a number of regulatory bodies including the NEB (1995), the OEB (1997) and the AEUB (2004).

In the US an attempt to develop an adjustment mechanism was made by only two regulatory agencies – the Federal Energy Regulatory Commission ("FERC") and the New York Public Service Commission ("NYPSC"). The FERC generally dropped its pursuit of a generic formula by about 1992 over legal concerns that a company-specific record must support the finding of a fair return. The FERC since has not departed from a case-by-case examination of the cost of equity. The NYPSC formula was created after an extensive process but was never adopted formally by the NYPSC.

Both FERC and NYSPC focused on a formula for deriving the cost of equity, rather than the long bond rates plus a pre-determined spread (Exhibit B-1, Appendix x, p.17).

In its Letter Decision, the NEB determined that the RH-2-94 Decision would not continue in effect and that the return on equity for the pipelines it regulates will no longer be determined by an adjustment mechanism.

In its Decision 2009-216, the AUC, following a generic hearing, determined that it would not employ an adjustment formula for 2010, but would initiate a process in 2011 "in order to allow the capital markets some time to return to traditional relationships or show evidence of what the new relationships may be." (AUC Decision, para 423-24)

The OEB is undertaking a consultative process on the cost of capital for the utilities it regulates, while proceedings are ongoing in Newfoundland and Québec.

EXCERPTS FROM UTILITIES COMMISSION ACT

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Partial relief

89 On an application under this Act, the commission may make an order granting the whole or part of the relief applied for or may grant further or other relief, as the commission considers advisable.

LIST OF APPEARANCES

G.A. FULTON, Q.C.	Commission Counsel
C.B.JOHNSON, Q.C. T. AHMED	Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc.
R.B. WALLACE	Joint Industry Electricity Steering Committee
C. WEAFER	Commercial Energy Consumers of BC
E. KUNG L. WORTH	British Columbia Old Age Pensioners Organization (“BCOAPO”) Active Support Against Poverty B.C. Coalition of People with Disabilities Council of Seniors' Organizations of B.C. End Legislated Poverty Federated Anti-Poverty Groups of B.C. Tenants' Rights Action Coalition
D. BURSEY	Industrial Customer Group, comprising Certainteed Gypsum Canada Inc., Domtar Pulp and Paper Products Inc., Federated Co-operatives Ltd., Teck Metals Ltd., Weyerhaeuser Company Ltd. and Zellstoff Celgar Limited Partnership
R.J. McDONELL	FortisBC Inc.
C. DONOHUE	Pacific Northern Gas Ltd.

E. Cheng	Commission Staff
F.Metcalfe	Contract Staff
Court Reporters	Allwest Reporting Ltd.

LIST OF PANELS

Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc

PANEL 1 – Company and Policy Panel

RANDY JESPERSEN	President and Chief Executive Officer
SCOTT THOMPSON	Vice President, Regulatory Affairs
ROGER DALL'ANTONIA	Vice President, Treasurer

PANEL 2 - Expert Opinion on a Benchmark Fair Return

JAMES H. VANDER WEIDE, PhD	Duke University

PANEL 3 - Expert Opinion on Capital Markets with Company View

DONALD A. CARMICHAEL, MBA	Financial Consultant
ROGER DALL'ANTONIA	Vice President, Treasurer

PANEL 4 - Expert Opinion on a Benchmark Fair Return

KATHLEEN C. MCSHANE, MBA, CFA	President, Foster Associates Inc.

The Joint Industry Electricity Steering Committee, the Commercial Energy Consumers Association of British Columbia and the British Columbia Old Age Pensioners Organization

LAURENCE G. BOOTH, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc.
Terasen Gas (Vancouver Island) Inc. and
Terasen Gas (Whistler) Inc.
collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated May 21, 2009 appointing the Commission Panel for the review of the Terasen Utilities Application for a Return on Equity and Capital Structure Application
A-2	Letter dated May 21, 2009 Preliminary Regulatory Timetable, Notice of Procedural Conference and Written Public Hearing.
A-2-1	Submitted at hearing September 28, 2009 Monthly Price Report - Canadian Natural Gas Focus dated September 2009
A-2-2	Submitted at hearing September 28, 2009 Newspaper article in the Vancouver Sun from September 2nd
A-2-3	Submitted at hearing September 29, 2009 Recalculated ROE without any adjustments
A-2-4	Submitted at hearing September 30, 2009 NATIONAL BANK FINANCIAL, SEPTEMBER 14, 2009 Corporate Indicative Issuance Spreads based on Government of Canada Yield Curve
A-2-5	Submitted at hearing October 1, 2009 Article entitled "How did economists get it so wrong" by Paul Krugman from the New York Times September 6, 2009
A-3	Letter dated June 9, 2009 Regulatory Timetable

Exhibit No.	**Description**
A-4	Letter dated June 24, 2009 – Reasons for Decision for Interim rate Relief
A-5	Letter dated June 29, 2009 BCUC IR No. 1 to Terasen Utilities
A-6	Letter dated July 31, 2009 BCUC IR No. 2 to Terasen Utilities
A-7	Letter dated September 2, 2009 Commission Panel Information Request No. 1 to Terasen Utilities
A-8	Letter dated September 3, 2009 Information Request No. 1 on the Evidence of Dr. Laurence Booth
A-9	Letter dated September 21, 2009 – Opening Statement
A-10	Letter dated October 27, 2009 – Oral Phase of Argument
A-11	Letter dated November 16, 2009 – Oral Phase of Argument
A-12	Letter dated November 18, 2009 - Oral Phase of Argument

APPLICANT DOCUMENTS TERASEN UTILITIES

B-1	Letter dated May 15, 2009 Terasen Utilities application for Return on Equity and Capital Structure.
B-2	Letter dated June 18, 2009 Terasen Utilities Reply Comments on Interim Relief
B-3	Letter dated July 20, 2009 Response to BCUC IR No. 1
B-3-1	Response to BCUC IR No. 1 Attachments Parts 1of 5
B-3-2	Response to BCUC IR No. 1 Attachments Parts 2 of 5
B-3-3	Response to BCUC IR No. 1 Attachments Parts 3 of 5
B-3-4	Response to BCUC IR No. 1 Attachments Parts 4 of 5
B-3-5	Response to BCUC IR No. 1 Attachments Parts 5 of 5
B-4	Letter dated July 20, 2009 Terasen Utilities Response to CEC IR No. 1

Exhibit No.	Description
B-5	Letter dated July 20, 2009 Terasen Utilities Response to JIESC-BCOAPO-CEC IR No. 1
B-6	Letter dated August 13, 2009 Terasen Utilities Response to BCUC IR No. 2
B-7	Letter dated August 13, 2009 Terasen Utilities Response to JIESC-BCOAPO-CEC IR No. 2
B-8	Letter dated August 13, 2009 Terasen Utilities Response to CEC IR No. 2
B-9	Letter dated September 3, 2009 Terasen Utilities IRs on the Evidence of Dr. L. Booth
B-10	Letter dated September 21, 2009 Erratum Response to IR No. 1.24.2 - page 80 of Exhibit B-3 correcting the table and highlighting the affected cells.
B-11	Letter dated September 21, 2009 Response to Commission Panel IR No. 1
B-12	Letter dated September 21, 2009 Terasen Utilities Witness Panels and Direct Testimony
B-12-1	Letter dated September 21, 2009 REPLACEMENT with corrections - Terasen Utilities Witness Panels and Direct Testimony
B-13	Letter dated September 24, 2009 Opening Statement of R.L. (Randy) Jespersen, CEO on Behalf of the Terasen Utilities
B-14	Submitted at hearing September 28, 2009 Speech from the Throne August 25, 2009
B-15	Submitted at hearing September 28, 2009 Response from the Terasen Gas Inc. revenue requirement application to a Commission Staff Request 2.31.2
B-16	Submitted at hearing September 28, 2009 Full BC Hydro Service Plan, the August, 2009 update
B-17	Submitted at hearing September 29, 2009 Moody's A-rated and Baa-rated Utility Bond Yields
B-18	Submitted at hearing September 29, 2009 common equity component of Fortis
B-19	Submitted at hearing September 30, 2009 Consumer Prices Consensus Economics, Consensus Forecasts, Long-Term Forecasts
B-20	Submitted at hearing October 1, 2009 TGI 2005 ROE Exhibit B-3, Response to BCUC IR 74.1, Appendix 74.1

Exhibit No.	Description
B-21	Submitted at hearing October 1, 2009 (PAGES 193 AND 194 FROM FINANCIAL THEORY AND CORPORATE POLICY BY COPELAND AND WESTON WITH ATTACHED TRANSCRIPT PAGES 795 AND 796 FROM 2005
B-22	Submitted at hearing October 1, 2009 PAPER BY DR. BOOTH ENTITLED "CAPITAL MARKET DEVELOPMENTS IN THE POST-OCTOBER 1987 PERIOD: A CANADIAN PERSPECTIVE
B-23	Submitted at hearing October 1, 2009 COLOURED GRAPH, WITH PAGES 790 TO 804 FROM TGI-TGVI ROE HEARING, NOVEMBER 17, 2005, VOLUME 5
B-24	Submitted at hearing October 1, 2009 TAB 2, APPENDIX A, RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST
B-25	Submitted at hearing October 1, 2009 TWO TABLES, BOTH HEADED "EXHIBIT, COMPARISON OF DR. BOOTH'S COST OF EQUITY RESULTS TO THE YIELDS ON MOODY'S A-RATED AND BAA-RATED UTILITY BONDS”
B-26	Submitted at hearing October 1, 2009 SCHEDULE 12, SPREADS SINCE 1990, WITH ATTACHED PAGE 15
B-27	Submitted at hearing October 1, 2009 70 REFERENCE: APPENDIX B, PAGE 1, LINES 18-25", PAGE 78
B-28	Letter dated October 20, 2009 Submission of Outstanding Undertakings

INTERVENOR DOCUMENTS

C1	**BRITISH COLUMBIA OLD AGE PENSIONERS’ ORGANIZATION (BCOAPO) -** Letter dated May 29, 2009 filing request by Leigha Worth for Intervenor Status
C1-2	Letter dated June 15, 2009 via Email BCOAPO submissions on interim relief
C2-1	Changed to Interested Party
C3-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) VIA EMAIL -** dated June 4, 2009, 2009 filing request by Christopher Weafer for Intervenor Status
C3-2	Letter dated June 12, 2009 CEC submissions on interim relief

Exhibit No.	Description
C3-3	Letter dated July 07, 2009 CEC information Request No. 1
C3-4	Letter dated July 31, 2009 CEC information Request No. 2
C4-1	**LOUELLA VINCENT VIA EMAIL -** dated May 31, 2009, 2009 filing request for Intervenor Status
C5-1	**BC HYDRO (BCH) ONLINE REGISTRATION -** dated June 5, 2009, filing request for Intervenor Status
C6-1	**FORTIS BC (FBC) ONLINE REGISTRATION -** dated June 5, 2009, filing request by Dennis Swanson for Intervenor Status
C6-2	Removed exhibit: under Arguments
C7-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR)** letter dated June 8, 2009, filing request by Duane Chapman for Intervenor Status
C8-1	**VANCOUVER ISLAND GAS JOINT VENTURE (VIGJV)** letter dated June 5, 2009, filing request by Karl Gustafson for Intervenor Status
C9-1	**ZELLSTOFF CELGAR (ZC)** letter dated June 8, 2009, filing request by Brian Merwin for Intervenor Status
C9-2	Letter dated June 8, 2009 Via Email ZC submissions on interim relief
C10-1	**PACIFIC NORTHERN GAS (PNG) - VIA EMAIL** letter dated June 8, 2009 filing request by Craig Donohue for Intervenor Status
C11-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** letter dated June 8, 2009 filing request by Brian Wallace for Intervenor Status
C11-1-1	Submitted at hearing September 30, 2009 EXHIBIT C11-11, AMENDED Page 5 CIA-Canadian Institute of Actuaries data Exhibits of Dr.Vander Weide taken from CIA
C11-2	Letter dated June 8, 2009 JIESC submissions on interim relief
C11-3	Letter dated July 6, 2009 **- VIA EMAIL** Joint Information Request on behalf of JIESC, BCOAPO and CEC
C11-4	Letter dated July 30, 2009 **- VIA EMAIL** Joint Information Request 2 on behalf of JIESC, BCOAPO and CEC
C11-5	Letter dated August 2009 JIESC submission Evidence of Laurence D. Booth

Exhibit No.	Description
C11-6	Letter dated September 15, 2009 Response of Dr. Booth to BCUC IR No. 1
C11-7	Letter dated September 15, 2009 Dr. Booth responses to TGI IR No.1
C11-8	Submitted at hearing September 28, 2009 Excerpt from BC Hydro Service Plan 2009/10 - 2011/12
C11-9	Submitted at hearing September 28, 2009 Excerpt from BC Hydro Service Plan 2009/10 - 2011/12 August 2009 Update
C11-10	Submitted at hearing September 29, 2009 Alberta EUB Decision Generic Cost of Capital
C11-11	Submitted at hearing September 29, 2009 JIESC materials for cross-examination of Terasen panel number two
C11-12	Submitted at hearing September 30, 2009 Scotia Bank Group Global Economic Research Weekly Trends from September 25, 2009
C11-13	Submitted at hearing September 30, 2009 Scotia Bank Group Global Economic Research – Global Forecast Update September 3, 2009
C11-14	Submitted at hearing September 30, 2009 Excerpt of Direct Testimony of James M Coyne on Behalf of ATCO Utilities ET AL November 20, 2008 in Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding
C11-15	Submitted at hearing September 30, 2009 Bank of Montreal Capital Markets report on Fortis Dated June 11, 2009
C11-16	Submitted at hearing October 1, 2009 ARTICLE FROM *THE JOURNAL OF FINANCE*, VOL. XLVI, NO. 4, SEPTEMBER 1991 ENTITLED "LIQUIDITY, MATURITY AND THE YIELDS ON U.S. TREASURY SECURITIES BY Y. AMIHUD AND H. MENDELSON
C11-17	Letter received October 14, 2009 JIESC/CEC/BCOAPO joint submission Dr. Booth's Responses to Undertakings
C12-1	**TECK COAL LTD (TC) – VIA EMAIL** Letter Dated July 06, 2009 filing by J. David Newlands to register as Intervenor

Exhibit No.	Description
C13-1	**INDUSTRIAL CUSTOMER GROUP (ICG) – VIA EMAIL** Letter Dated July 24, 2009 filing by and for David Bursey, Katie Seymour and Harold Todd to register as Intervenor (Certainteed Gypsum Canada Inc., Domtar Pulp and Paper Products Inc., Federated Co-operatives Ltd., Teck Metals Ltd., Weyerhaeuser Company Ltd., Zellstoff Celgar Limited Partnership)

INTERESTED PARTY DOCUMENTS

D-1	**CENTRAL HEAT DISTRIBUTION (CHD)** Letter Dated May 22, 2009 John Barnes filing to register as Interested Party
D-2	**COPE 378 (COPE) ONLINE REGISTRATION -** dated June 5, 2009, filing request by Kevin Smyth to register as Interested Party
D-3	**BP CANADA ENERGY COMPANY ONLINE REGISTRATION-** dated June 3, 2009, filing request by Cheryl Worthy to register as Interested Party
D-4	**BRITISH COLUMBIA TRANSMISSION CORPORATION (BCTC) ONLINE REGISTRATION -** dated June18, 2009, filing request by Gordon Doyle to register as Interested Party
D-5	**ACCESS GAS SERVICES INC. – ONLINE REGISTRATION** dated July 20, 2009 filing request by Tom Dixon for Interested party status

AUC
Alberta Utilities Commission

2009 Generic Cost of Capital

November 12, 2009

ALBERTA UTILITIES COMMISSION
Decision 2009-216: 2009 Generic Cost of Capital
Application No. 1578571
Proceeding ID. 85

November 12, 2009

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ALBERTA UTILITIES COMMISSION
Calgary Alberta

Decision 2009-216
Application No. 1578571
2009 GENERIC COST OF CAPITAL **Proceeding ID. 85**

1 INTRODUCTION

1.1 Background

1. In Decision 2004-052,[1] (the Generic Cost of Capital Decision or GCC Decision) dated July 2, 2004, the Alberta Energy and Utilities Board (EUB or Board) established a single generic Return on Equity (ROE) for all utilities participating in the proceeding. It also adopted a formula approach for determining an annual generic ROE and set common equity ratios for each of the applicant utilities.

2. In the GCC Decision, the Board determined that it would seek the views of parties on whether the adjustment formula continued to yield a fair ROE prior to the establishment of the common ROE for the year 2009. The GCC Decision also established that the generic ROE could be reviewed prior to 2009 if the ROE resulting from the adjustment mechanism for years prior to 2009 was less than 7.6 percent or greater than 11.6 percent.

3. Further to the contemplated five year review of the adjustment formula the Alberta Utilities Commission (Commission or AUC) initiated a proceeding[2] on February 21, 2008 to determine whether the ROE formula and/or the common equity ratios should again be reviewed on a generic basis. All electric, gas and pipeline utilities regulated by the Commission were invited to participate in this preliminary proceeding. The Commission's Notice identified the following two issues:

- does the Generic Cost of Capital adjustment formula determined by the EUB in the GCC Decision continue to yield a fair ROE, (the Preliminary ROE Question); and
- should the capital structures for all applicable utilities be addressed on a generic basis (the Preliminary Capital Structure Question)?[3]

4. After considering the submissions of parties, the Commission issued Decision 2008-051[4] on June 18, 2008, finding that there was sufficient evidence to warrant a review of the generic ROE level and adjustment formula and of utility capital structures. The Commission determined that capital structures would be considered on a utility-specific basis in a generic proceeding

[1] Decision 2004-052 - Generic Cost of Capital – AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution. Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks) Nova Gas Transmission Ltd. (Application 1271597) (Released: July 2, 2004).

[2] Application No. 1561663, ID No. 15, Generic Cost of Capital – Preliminary Questions Proceeding.

[3] Application No. 1561663, ID No. 15, Generic Cost of Capital – Preliminary Question Proceeding, Notice issued February 21, 2008.

[4] Decision 2008-051 - Generic Cost of Capital – Preliminary Questions Proceeding, (Application 1561663) (Released: June 18, 2008).

along with the ROE level and adjustment formula. The Commission also recognized that ATCO Gas, in a separate proceeding,[5] had applied for an equity ratio increase for 2008 and 2009. ATCO Pipelines, also in a separate proceeding,[6] had applied for both equity ratio and ROE increases for 2008 and 2009. In the interest of efficiency, the Commission determined that ATCO Gas's and ATCO Pipelines' cost of capital applications for 2008 could be dealt with in the generic proceeding. Subsequently, ATCO Pipelines reached a Negotiated Settlement Agreement (NSA) with respect to its 2008 and 2009 revenue requirements. This NSA was approved by the Commission in Decision 2009-033[7] and therefore ATCO Pipelines was no longer requesting that the Commission address the 2008 ROE and capital structure changes included in its original general rate application.

1.2 Procedural Background

5. On July 25, 2008, pursuant to section 8(2) of the *Alberta Utilities Commission Act*, S.A. 2007, c. A 37.2, and in accordance with Decision 2008-051, the Commission initiated the present proceeding by issuing a public notice (Notice)[8] for the 2009 Generic Cost of Capital Proceeding (Proceeding ID. 85, Application No. 1578571) (2009 GCC Proceeding or Proceeding). The Notice indicated that the 2009 GCC Proceeding would review the level of the generic return on equity for 2009, the ROE adjustment formula and the capital structures of the utilities on a utility-specific basis. The Proceeding would not deal with the cost of debt component of the cost of capital. This Notice applied to all gas distribution, electric distribution and transmission and pipeline companies regulated by the AUC. In addition, the Notice indicated that:

> Other utilities (Other Utilities) that may wish to participate in the 2009 GCC Proceeding include, but are not limited to:
>
> Various investor-owned water utilities regulated by the Commission
> EPCOR Energy Alberta Inc. (Regulated Retail Electricity Operations)
> ENMAX Energy Corporation (Regulated Retail Electricity Operations)
> Direct Energy Regulated Services (Regulated Retail Electricity and Gas Operations)
> City of Lethbridge (Electricity Distribution)
> City of Red Deer (Electricity Distribution)
>
> Other Utilities in determining whether or not to participate in the 2009 GCC Proceeding should note that the Commission decision resulting from this proceeding, may be considered by the Commission with respect to cost of capital related matters in future proceedings relating to Other Utilities. Regarding regulated retail electricity and gas operations, the generic cost of capital may be applied in any cases where a return-on-rate-base approach is used, however a review of appropriate retail return margins will not be included in this proceeding. With respect to water utilities, the generic cost of capital results may be considered but may not be definitive in setting ROE or common equity ratios.

5 Application No. 1553052, ID No. 11 ATCO Gas 2008-2009 General Rate Application Phase I.
6 Application No. 1527976, ID No. 13 ATCO Pipelines 2008-2009 General Rate Application Phase I.
7 Decision 2009-033 - ATCO Pipelines, 2008-2009 General Rate Application Phase I Settlement Agreement (Application 1527976) (Released: March 18, 2009).
8 Exhibit 1.

All participating utilities and Other Utilities shall be considered as applicants in the 2009 GCC Proceeding.

6. The Notice was published in the four major daily newspapers in Alberta on July 29, 2008. In addition, the Notice was e-mailed to all parties involved in the Cost of Capital Preliminary Questions proceeding as well as to the Commission's contact lists for utilities proceedings.

7. A list of all participants who submitted a Statement of Intent to Participate (SIP) is set out in Appendix 1.

8. On July 25, 2008, in accordance with the Notice, the Commission issued a Preliminary Scoping Document and Preliminary Minimum Filing Requirements.[9] A procedural schedule, Final Scoping Document and Final Minimum Filing Requirements was issued by the Commission on September 4, 2008.[10]

9. The schedule for the Application was amended a number of times throughout the proceeding. The final process followed by the Commission for the Application is set out below:

Table 1. Procedural Schedule

Process Step	***Deadline Date***
Participation Closing Date and Submission of Statements of Intent to Participate	August 14, 2008
Comments on Preliminary Scoping Document, and Preliminary Minimum Filing Requirements	August 14, 2008
Commission Issues Final Scoping Document and Final Minimum Filing Requirements	September 4, 2008
Utility Evidence Received	November 20, 2008
Information Requests to Utilities	January 6, 2009
Information Responses from Utilities	February 6, 2009
Intervener Evidence	March 2, 2009
Information Requests to Interveners	March 24, 2009
Information Responses from Interveners	April 14, 2009
Rebuttal Evidence	May 4, 2009

10. The Commission conducted a public hearing from May 19 to June 16, 2009, in the Commission's hearing room in Calgary. A list of parties who appeared at the hearing is included in Appendix 2. The Commission sat for a total of 21 hearing days.

11. By letter dated April 21, 2009[11] NOVA Gas Transmission Ltd. (NGTL) withdrew from the Proceeding in light of the National Energy Board (NEB) issuing a Certificate of Public Convenience and Necessity on April 15, 2009 for the continued operation of NGTL's Alberta System under federal jurisdiction and regulation effective April 29, 2009.

[9] Exhibit 2.
[10] Exhibit 36.
[11] Exhibit 261.

12. The Commission issued a letter dated April 13, 2009[12] advising parties that the NGTL evidence would remain on the record of this Proceeding and that the extent to which it would be considered by the Commission would be a question of weight. In a letter dated April 29, 2009[13] the Commission approved the request of the ATCO Utilities to incorporate into its case in this Proceeding the evidence of Mr. Engen filed by NGTL, including relevant Information Request Responses and to permit the filing of Supplemental Written Direct Evidence of Mr. Engen. The Commission noted that AltaGas Utilities Inc. (AltaGas) had indicated that it was not prepared to sponsor NGTL evidence absent acceptance by the Commission of one of its proposals in respect of that evidence. AltaGas indicated however, that its expert, Dr. Vilbert would continue to rely on the analysis that he and Dr. Kolbe had performed for NGTL which had relied on the business risk evidence filed by NGTL and the expert testimony filed by Dr. Carpenter and Mr. Engen. The Commission also confirmed that all of the NGTL filed evidence remained on the record of this Proceeding. Accordingly, other than the evidence of Mr. Engen which was sponsored by the ATCO Utilities, the evidence of NGTL and of the experts filed by NGTL was considered by the Commission to be unsponsored evidence. Parties were invited to provide submissions on the weight to be accorded to such unsponsored evidence in final argument.

13. At the conclusion of the oral hearing parties wishing to make oral submissions in argument were provided the opportunity to do so on July 23, 2009. Written Argument was also filed on July 23, 2009 by all active parties. Reply Argument was filed by all active parties on August 13, 2009. On August 14, 2009 the ATCO Utilities filed a correction to its Reply Argument. The Commission considers the record of this proceeding to have closed on August 14, 2009.

14. The panel assigned to the Proceeding consisted of Willie Grieve, AUC Chair, and of the panel, Commissioner Tudor Beattie, Q. C., Commissioner Mark Kolesar, Commissioner Anne Michaud and Commissioner Bill Lyttle.

15. All natural gas distribution and transmission utilities and all electric distribution and transmission utilities regulated by the Commission and interveners representing major customer interests registered to participate in the proceeding. The record of this Proceeding is voluminous including extensive detailed written evidence, information request responses, testimony and argument. The Commission issued several rulings throughout the course of the proceeding on various evidentiary and procedural matters.

16. The Commission heard from cost of capital, investment banking, credit rating and financial market experts for both the utilities and the interveners. The following experts appeared at the oral hearing:

- Dr. Michael J. Vilbert for AltaGas Utilities Inc. specializes in financial and regulatory economics and is an expert in cost of capital, financial planning and valuation matters.
- Ms. Susan Abbott for AltaLink Management Ltd. is an expert in rating agency matters with over 20 years, including international, rating experience.
- Dr. Vander Weide for AltaLink Management Ltd., EPCOR Distribution & Transmission Inc., EPCOR Energy Alberta Inc. and FortisAlberta Ltd. is an expert on financial and economic theory and practice and on the cost of capital.

[12] Exhibit 229.
[13] Exhibit 273.

- Mr. James Coyne for the ATCO Utilities has expertise in financial, regulatory, strategic, matters and provides litigation support services to clients in the power and utilities industries.
- Mr. Aaron Engen for the ATCO Utilities is an investment banker specializing in energy infrastructure and is an expert in capital markets and mergers and acquisitions transactions.
- Dr. J. Stephen Gaske for the ATCO Utilities consults in financial and economic matters with regulated public utilities and pipelines and is also a cost of capital expert.
- Ms. Kathleen McShane for the ATCO Utilities has extensive background in financial and regulatory issues and is a cost of capital expert.
- Dr. John Neri for ENMAX Power Corporation is an economist and has provided testimony in various regulatory proceedings in the areas of cost of capital, cost allocation and rate design, market power and sales forecasts.
- Mr. Hugh Johnson for The City of Calgary is an expert in business risk and cost of capital.
- Dr. Lawrence Booth for CAPP and The City of Calgary is an expert in the areas of corporate finance, return on equity and capital structure.
- Dr. Andrew Safir for CAPP is an expert in economics and regulation.
- Mr. Marcus for the UCA is an economics expert with respect to electric and gas utilities.
- Dr. Kryzanowski and Dr. Roberts for the UCA are experts in finance, economics and utility rate of return matters.

In addition to these experts, numerous company and intervener witnesses appeared, as listed in Appendix 2.

17. In reaching the determinations contained within this Decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

1.3 Background to Generic Cost of Capital Approach Adopted in Decision 2004-052

18. The British Columbia Utilities Commission was the first regulator in Canada to adopt an ROE adjustment formula in June of 1994. In the fall of 1994, the NEB held the Multi-Pipeline Cost of Capital Proceeding (RH-2-94). In the RH-2-94 Decision the NEB also adopted a formula for adjusting the ROE on an annual basis. Subsequently, the Public Utilities Board of Manitoba adopted an ROE adjustment formula in May of 1995 and the Ontario Energy Board adopted a similar ROE adjustment formula in 1997. In Québec, the Régie de l'énergie has, since its decision D-99-11 of February 10th, 1999, applied a *de facto* generic ROE adjustment formula based on a Capital Asset Pricing Model (CAPM) with an annual adjustment based on the forecasted change in the risk-free return.[14]

[14] Exhibit 132.02, Response to Information Request CAPP-Coyne-1(b).

19. As noted above, the EUB adopted its annual ROE adjustment formula in 2004. At that time, the impacts of electric and gas deregulation, unbundling and corporate reorganizations had added significantly to the number of individual utilities in Alberta. Administrative efficiency in dealing with cost of capital evidence in rate proceedings was an impetus for the Board and parties to consider a generic ROE formula approach and a single proceeding for setting capital structures for all utilities.

1.4 Deregulation and Unbundling of Alberta Electric Utilities

20. For many years there were only two investor-owned electric utilities in Alberta, Alberta Power Limited and TransAlta Corporation. Prior to deregulation of the electricity market in Alberta, these two investor-owned utilities were "fully integrated" utilities, consisting of generation, transmission, distribution, and retail functions.

21. In 1996, the provincial hourly power pool was set-up and the process of unbundling the electric utilities was underway. At the beginning of 2001, the electric utilities were unbundled into the components of generation, transmission, distribution, and retail service.

22. New generation and competitive retail were completely deregulated as to rate of return. Existing generation became quasi-regulated as the physical generation plants sold off regulated 20-year contracts (or expected life of plant if less than 20 years) on their output in return for a more-or-less traditional regulated return. However the return would be realized through contractual payments rather than regulated in the traditional way. Once these 20-year contracts were approved by the regulator there was little further involvement of the regulator (with the exception that contractual disputes could be brought to the regulator). These contracts included a formula ROE similar to the NEB's formula and the formula subsequently adopted in Alberta in 2004.

23. The monopoly functions of electricity transmission and distribution remain fully regulated. The competitive retail functions are offered through competitive retailers and the distribution utilities are required to provide a regulated retail option.

24. The former integrated electric utilities created subsidiaries or divisions to separate their generation, transmission, distribution, competitive retail and regulated retail functions. In some cases portions of the former companies were sold off.

25. As a result of the unbundling, the former Alberta Power is now regulated by the AUC as two separate utilities, ATCO Electric Distribution and ATCO Electric Transmission. Alberta Power's retail function was eventually sold to Direct Energy Marketing Ltd. (although ATCO Electric remains ultimately responsible for the regulated retail function) and its generation (unregulated and or contracted under long term Power Purchase Arrangements) was retained by other ATCO subsidiaries. TransAlta elected to sell off its transmission function, which is now called AltaLink L.P. TransAlta's distribution function was also divested to eventually become FortisAlberta.

26. Beginning in 2004, the regulation of the rates charged by the municipally-owned electricity distribution utilities for Calgary and Edmonton came under the jurisdiction of the EUB, and now the Commission. The generation and transmission functions of the City of Edmonton had been under the Board's jurisdiction for many years. The transmission function of Calgary, Red Deer and Lethbridge came under Board jurisdiction in 2006.

1.5 Deregulation and Unbundling of Alberta Natural Gas Utilities

27. Natural gas distribution in Alberta has, for the most part, always been investor-owned, with the exception of a number of small municipal gas distribution systems, the largest being Medicine Hat, and several rural gas distribution cooperatives.

28. Two vertically integrated companies, Northwestern Utilities Limited (which included the gas portion of Northland Utilities Limited) and Canadian Western Natural Gas Company Limited, were amalgamated into ATCO Gas and Pipelines Ltd. in 1988. As a result, the distribution operations now make up the separately regulated ATCO Gas division. The smaller AltaGas Ltd. which is made up of the former Plains-Western Gas, then Centra Gas, and the former Bonnyville Gas Company, also provides predominantly distribution services.

29. During the 1980s it was possible for large gas consuming industries to procure their gas commodity from sources other than their gas distributor. By the late 1990s it was also possible for small retail and residential customers to procure gas under contract from gas marketers. The gas distribution utilities continued to be required to provide a regulated gas price to small retail and residential customers. In 2004, ATCO Gas contracted with Direct Energy Regulated Services, a business unit of Direct Energy Marketing Limited, to be its regulated default supplier.

30. NGTL (formerly Alberta Gas Trunkline Limited and now owned by TransCanada PipeLines Limited) was regulated by the Board and subsequently the Commission for decades, although initially on a complaint basis only. However, as noted above, effective April 29, 2009, NGTL came under federal jurisdiction and is now regulated by the NEB. The much smaller ATCO Pipelines (the transmission division of the amalgamation that resulted in ATCO Gas and Pipelines Ltd.) remains under the jurisdiction of the Commission.

1.6 Challenges

31. Restructuring of the industry into separate generation, transmission, distribution and retail functions, and the subsequent corporate restructuring among the companies that the Board regulated led to two challenges, both of which persist today. First, the number of companies for which a fair return must be established has increased due to the unbundling of the formerly integrated utilities. With this large increase in the number of regulated utilities, a generic approach to determining ROE and the adoption of an annual ROE adjustment formula was considered to be more efficient.

32. The second challenge followed from the fact that the Alberta regulated utilities no longer trade on the stock market as relatively pure-play regulated utilities. During the 1980s TransAlta traded on the stock market as a relatively pure-play regulated electric utility. Alberta Power was then (as now) owned by Canadian Utilities Inc., which also traded as a relatively pure-play regulated utility with electricity and gas distribution subsidiaries. At that time, the Board had relatively good visibility into investor reactions to the level of returns for the Alberta utilities it regulated. However, with the structural changes in the industry, the companies largely restructured into holding companies with subsidiaries or divisions in a number of industry sectors, each of which were (and still are) individually regulated on a stand-alone basis. Further complicating the task of regulating these subsidiary companies, some holding companies became increasingly involved in unregulated activities, sometimes outside of Canada, and the generation activities of the holding companies became deregulated. As a result, it was no longer possible to directly see the market response to awarded rates of return on the utilities as stand-alone

regulated entities. It is the subsidiary utilities for which the Board, and now the Commission, was required to establish a regulated ROE and capital structure. This was referred to, by one expert witness in this proceeding, as the "dirty window" problem.

1.7 Alberta Energy and Utilities Board Decision 2004-052

33. In Decision 2004-052, the Board established that the generic ROE, for all of the companies for which it was required to establish a fair return, should be set at 9.6 percent for 2004. The Board applied the generic 9.6 percent ROE to all companies uniformly, but adjusted the equity ratio for each company, or group of companies in a single sector, to account for differences in risk.

34. The Board also approved an annual ROE adjustment formula, as follows:

$ROE_t = 9.60\% + [0.75 \text{ x } (YLD_t – 5.68\%)]$
where YLD_t = the forecast long-term Canada bond yield for year t.

35. For the purposes of the formula, the Board also adopted the NEB's approach to establishing the forecast for long-term Canada bond yields, calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

36. As stated earlier, the Board determined that it would seek the views of parties on whether the adjustment mechanism continued to yield a fair ROE prior to the establishment of the common ROE for the year 2009. The Board also established that the generic ROE could be reviewed prior to 2009, if the ROE resulting from the adjustment mechanism for years prior to 2009 was less than 7.6 percent or greater than 11.6 percent. Additionally, any party, at any time, would be free to petition the Board to consider a review of the adjustment formula, or to exempt a particular party from its application. The Board recognized that there would be an element of judgment involved in determining whether circumstances had changed sufficiently to warrant a review, and that the ROE and adjustment mechanism determined by the Board should be entitled to a presumption of reasonableness, with any party seeking early review or an exemption bearing the onus of demonstrating that circumstances had rendered them unreasonable. The petitioning party would bear the onus of demonstrating a material change in facts or circumstances to merit a review of the adjustment formula or an exclusion from the formula.

37. The following table provides the results obtained under the Board's generic ROE annual adjustment formula from 2004 to 2008 and what the result would be if it applied in 2009:

Table 2. Annual ROE Adjustment Formula Results

	2004	2005	2006	2007	2008	2009 If Continued
	(%)					
(a) 10-Year Canada Bond Yield - Consensus Forecast		5.05	4.55	4.15	4.50	3.85
(b) Spread of 30-year versus 10 year		0.50	0.23	0.07	0.05	0.51
(c) 30-Year Canada Yield Approved	5.68	5.55	4.78	4.22	4.55	4.36
(d) Change in 30-Year Yield Versus Prior Year		-0.13	-0.77	-0.56	0.33	-0.19
(e) 75% of (d)		-0.10	-0.58	-0.42	0.25	-0.14
Generic ROE	9.60	9.50	8.93	8.51	8.75	8.61

38. With respect to capital structure, the Board determined that setting an equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. In this regard, the Board found that the assessment of the level of business risk of the utilities is also subjective. Consequently, the Board considered that there is no single accepted mathematical way to make a determination of equity ratios based on a given level of business risk. The equity ratios approved by the Board in 2004 are set out in Table 11.

39. With respect to the adjustment of equity ratios, the GCC Decision indicated, at page 55, that it would be more appropriate to address future changes in capital structure in utility-specific rate proceedings. This reflected the view that a utility-specific approach is warranted in cases where the investment risks of a particular utility have changed materially for reasons specific to that utility. However, as discussed above, the Commission determined in Decision 2008-051 to also review capital structures in this Proceeding.

1.8 Placeholder for 2009

40. After canvassing parties, in a letter dated December 1, 2008, the Commission established a 2009 ROE placeholder for all utilities which had not already established a 2009 ROE by way of negotiated settlement or regulatory decision. The 2009 placeholder was set equal to the 2008 generic ROE of 8.75 percent.[15] This placeholder is to be replaced by the 2009 ROE determination made in this Decision. The 2008 generic ROE percentage was used for administrative convenience given the time of the year and the fact that many utilities already had 2009 interim rates in place incorporating the 2008 ROE.

41. The annual adjustment formula adopted by the Board, and most other Canadian regulators using an ROE adjustment formula, is based on the financial concept that the required ROE for an investment encompassing any degree of risk includes a risk premium above the risk free rate of return. The risk free rate of return has generally been considered as the return just large enough to compensate an investor for the *expected* (as opposed to the actual) loss of purchasing power due to inflation over the term of the investment, plus an additional incentive amount for delayed spending, where there is absolute certainty that the initial investment and the return will be paid. In practice, the risk free rate has been the yield on long-term Government of Canada bonds (long Canada bonds).

[15] Exhibit 64.

42. The annual adjustment formula adopted by the Board assumed that the fair ROE for Alberta utilities would increase or decrease by approximately 75 percent of any change in the risk free rate, as represented by long Canada bonds.

1.9 Context for Decision

43. It is of assistance in understanding the evidence provided in this Proceeding to review the context in which it was prepared. Observations put forward by parties on increased economic globalization, the performance of financial markets, the financial performance of utilities, anticipated infrastructure expansions in Alberta and the advent of the current financial crisis that began to develop in 2007, all form part of this context and influence the evidence upon which the Commission must determine a fair return on equity for Alberta utilities for 2009.

44. The utilities provided contextual evidence on the financial markets since the issuance of Decision 2004-052. They pointed to the growing differential between corporate bond yields and the government bonds used in the annual ROE adjustment formula (which compresses the spread between corporate bond yields and the formula ROE) as evidence that the formula was not producing a fair ROE.

45. AltaLink noted that the allowed ROE of 9.6 percent, established in the 2004 GCC Decision, was 4.13 percent higher than the average yield for “A” rated Canadian corporate bonds during 2004, the first year under the adjustment formula. It then noted that the spread gradually decreased from mid-2005 to mid-2007 indicating that the corporate bond yields were increasing while the formula ROE was decreasing.[16]

46. The utilities also submitted that the current credit crisis has resulted in credit spreads widening and yields on corporate bonds increasing substantially, while the yield on government bonds is decreasing. AltaLink stated the following with respect to the impact on utilities of the current credit crisis:

> Significant and fundamental changes have occurred in global capital markets since the 2004 GCC Decision was issued, and in particular since August 2007 when financial markets were adversely impacted by the collapse of the ABCP [Asset Backed Commercial Paper]. The global impact of the ABCP collapse resulted in a step change in global financial markets, as evidenced by the significant increase in corporate credit spreads. In response to the ABCP collapse, the central banks in Canada and most major countries lowered interest rates and injected massive amounts of cash into their economies to maintain liquidity and stabilize capital markets. Government of Canada bond yields dropped significantly in the months following the ABCP collapse, particularly for 10-year maturities, while yields on A-rated corporate debt increased dramatically. In addition, the widening of credit spreads between 10-year and 30-year Government of Canada securities following the onset of the ABCP crisis confirms that global financial markets were becoming increasingly risk averse, demanding higher returns for longer-term corporate debt instruments (as shown in Firuge1.2a above).
>
> The fundamental changes in global capital markets resulting from the ABCP collapse have been overshadowed by the recent collapse in global financial markets that has effectively shut down issuance of corporate debt and equity. This continuing crisis is occurring notwithstanding the fact that central banks around the world have taken unprecedented measures, such as the $700 billion bailout of U.S. banks. While

[16] Written Evidence of AltaLink Management Ltd., Exhibit 57.03, pages 4-7.

> Government of Canada bond yields increased slightly during the fourth quarter of 2008, yields on A-rated corporate debt have increased dramatically during the same period following a steady widening of credit spreads during the second and third quarters. The impact on corporate credit markets has been so severe that, until very recently, there was virtually no activity in the long-term debt markets or the commercial paper markets. Figure 1.3a below shows the diminished levels of Canadian Corporate Issuances that has taken place recently compared to levels from January 2007.
>
> At the same time, there has been a significant negative impact in markets for equity securities, as evidenced by the significant decline in the value and the increase in volatility of Canadian and global stock market indices (please refer to Figure 1.3b below). Since equity instruments are subordinate to secured debt instruments, the widening of longer-term credit spreads and the massive declines in stock prices during 2008 are clear indicators that investors require higher returns on equity to compensate for higher investment risks associated with equity instruments during the current crisis in global financial markets.[17] (figures omitted)

47. AltaLink summarized its concerns by stating:

> At a time when global capital markets are in crisis and fundamentally different from 2004, the compression between ROEs (as determined using the ROE Formula) and yields on investment grade utility senior secured debt is not reasonable and no longer makes economic sense.[18]

48. The utilities also suggested that government monetary policy has reduced interest rates to abnormally low levels in order to stimulate the economy. This action is reflected in the interest rates on government issued debt. They further suggested that an adjustment formula that is tied to long Canada bonds will not properly reflect a fair return on equity for utilities. The Commission notes the following exchange between counsel for the UCA and Mr. Coyne, an expert appearing for the ATCO Utilities:

> Q. Now, on line 1 of page 4 you state: "Since the platform of the CAPM approach depends on the risk-free rate, which is normally the current or forecasted yield on a 10-year or 30-year government bond, the result produced by the CAPM approach are not reliable during periods when government interest rates are abnormally low."
> Mr. Coyne, have you conducted any studies or analysis to determine what is a normal government interest rate, and how have you determined that government interest rates are abnormally low?
>
> A. MR. COYNE: Well, I examined government interest rates going back over the last 50 years, and they are at record lows. I think there is substantial evidence in that regard. The last time we've seen rates this low in Canada I believe date back to the 1930s. So I think, certainly in my life time, these are the lowest government bond rates that we've seen, and I think there is substantial evidence on the record in that regard.[19]

17 Written Evidence of AltaLink Management Ltd., Exhibit 57.03, pages 6-8.
18 Written Evidence of AltaLink Management Ltd., Exhibit 57.03, page 10.
19 Transcript, page 604, line 20 to page 605, line 15.

49. Interveners cautioned the Commission against overreacting to the credit crisis. Dr. Booth, on behalf of CAPP, stated:

> Overall, and despite the current turmoil in financial markets I would recommend that the AUC continue with its formula ROE adjustment. It has stood the test of time in delivering fair and reasonable ROEs and by and large removed an enormous amount of repetitive ROE testimony to allow the AUC to deal with more important issues.[20]

50. Leading into the oral hearing in the Proceeding there was considerable uncertainty and there were several conflicting views on how quickly the economy and debt and securities markets would recover. Some evidence was led to indicate that credit spreads were again narrowing and that the financial markets may be starting to recover. However, parties disagreed on the extent and duration of the impacts of the financial crisis on the economy as a whole and on utilities in particular.

51. Notwithstanding the issues and economic developments discussed above, the Commission observes that since the issuance of Decision 2004-052 in July 2004 and before the onset of the economic crisis, there had been few indications that the adjustment formula was not producing an appropriate annual ROE. Decision 2004-052 and the annual formula had resulted in a range of ROEs with a high of 9.60 percent and a low of 8.51 percent well within the off-ramp triggers set out in the Decision of 7.6 percent and 11.6 percent. Further, until the present Proceeding, no party, other than ATCO Gas with respect to its equity ratio for 2008 and ATCO Pipelines with respect to ROE and capital structure for 2008, had requested a review of the generic formula or a change to the allowed capital structure determined in Decision 2004-052.

52. The Commission notes the National Energy Board (NEB) issued Decision RH-1-2008, Trans Québec & Maritimes Pipelines Inc., Cost of Capital for 2007 and 2008 (TQM Decision). TQM had been awarded an ROE set by the NEB's annual adjustment formula, which was almost identical to the Board's annual adjustment formula. TQM's allowed equity ratio was 30 percent. TQM requested an ROE of 11 percent on a deemed equity component of 40 percent. TQM had indicated this was equivalent to an After Tax Weighted Average Cost of Capital (ATWACC) of 6.9 percent.

53. The NEB found that financial conditions had changed since its formula was introduced. The NEB concluded that its ROE formula relied on a single variable, the long Canada bond yields, and that this may not be capturing all the changes in financial conditions.

54. The NEB looked at regulated returns as well as market based returns on various proxy groups including Canadian utilities and U.S. federally regulated and state regulated natural gas local distribution utilities and transmission pipelines. In its analysis, the NEB concluded that Canadian utilities are competing for capital on a global basis and Canada mostly interacts with the U.S. The NEB considered that comparisons to U.S. utilities were useful to its analysis.

55. The NEB approved a market-based ATWACC approach and allowed TQM an ATWACC of 6.4 percent and left TQM free to set its own equity ratio. This result was equivalent to

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[20] Revised Evidence of Dr. Booth, Exhibit 292.03, page 4.

awarding an ROE of 9.7 percent assuming a 40 percent equity ratio, or 11.2 percent assuming a 32 percent equity ratio.[21]

56. It is in this economic and regulatory context that parties to the Proceeding advanced evidence and argument on what combination of ROE and capital structure was required in order to produce a fair return on capital. This evidence included submissions on whether the annual change in the risk free rate as represented by long Canada bonds upon which the Board's ROE adjustment formula was based ever produced, or could continue to produce a fair return on capital. Further, if the validity of the formula was indeed in question, parties disagreed whether an economic recovery from the current economic crisis would restore the integrity of the formula.

1.10 Summary of Utilities' Positions

57. As noted above, the Commission was presented with a wide range of conflicting evidence and polarized opinions on how it should approach setting a fair return on capital for Alberta utilities for 2009. There was also significant disagreement on whether the Commission should set the fair return for 2009 only, or for 2009 and 2010, and whether it should abandon, amend, or replace its annual adjustment formula.

58. In general, the utilities argued that the annual adjustment formula should be modified or abandoned because Canadian equity investors require a risk premium in excess of the risk premium implied by the formula. In addition, the utilities generally proposed that the equity portion of their capital structures should be increased. The utilities advanced numerous arguments in support of these contentions.

59. On the strength of a number of analyses, the utilities argued that allowed rates of return on equity and allowed equity ratios awarded by U.S. regulators are both significantly higher for utilities of similar risk. They argued that the annual adjustment formula reduces the allowed ROE by a greater amount than has been the typical experience with U.S. regulators, when the yield to maturity on long-term government bonds declines, as it had during the credit crisis. Some utility experts also suggested that the volatility of returns on Canadian utility stocks now exceeds or approximates the volatility of returns on the Canadian stock market index as a whole. Accordingly, they argued the equity risk premium required in setting a fair return for Canadian utilities must now be higher than the equity risk premium implied by the annual adjustment formula. As a result, they argued, the annual adjustment formula produces a lower ROE estimate at a time when the increased risks of volatile economic and capital market conditions are causing capital costs to increase dramatically.

60. Commenting on the effects of the credit crisis on the bond market, Susan Abbott, an expert witness appearing for AltaLink stated:

> This is not the bond market we have known for the last 15 years, and marks a "new normal." The deleveraging rate around the world is very high, and the effect of that on the overall worldwide economy is unknown. What it does imply, however, is lower levels of spending which will make economic recovery more difficult. In addition, what the

[21] TQM Decision, National Energy Board, Decision RH-1-2008, Trans Quebec & Maritimes Pipelines Inc.,Cost of Capital for 2007 and 2008, page 81, footnote 38.

> economy recovers to will be very different from the days of easy, cheap credit we have been used to.[22]

61. The utilities also submitted that since Decision 2004-052 fundamental financial market and economic changes have occurred which call into question the fairness of the returns supported by allowed ROEs set by the annual adjustment formula. Specifically, the dramatic decline in the ratio of government debt to GDP and resulting supply/demand imbalance for such instruments, and deep investor concerns over economic and financial market uncertainty, have been putting very heavy downward pressure on Government of Canada bond yields. The substantial and growing imbalance is resulting in seriously (and artificially) lower allowed ROEs under the annual adjustment formula. In addition, highly volatile spreads between the 10-year and 30-year Government of Canada bonds have been negatively affecting allowed ROEs. According to the utilities, these developments suggest there are fundamental issues with the viability of the formula.

62. With respect to equity ratios, the utilities generally argued that Canadian utilities have greater financial risk than U.S. utilities because U.S. utilities generally have higher allowed equity ratios. As a result, they argued the allowed overall rate of return for the utilities is significantly less than the overall return that investors can earn on other investments of similar risk.

63. The utilities further submitted that the Commission's existing approach to determining allowed ROEs and capital structures for Alberta's utilities does not satisfy the fair return standard laid down by the courts which requires a fair return to satisfy a fairness standard including a comparable investment standard, a financial integrity standard and a capital attraction standard. The ATCO Utilities also argued that a "fairness deficit" has prevailed for a decade when Alberta allowed returns are compared to allowed returns of U.S. utilities and that this deficit has grown in recent years under the current formula.

64. Utility experts submitted that there are no appreciable differences in regulatory risk, financial risks, operating characteristics, tax structure, legislation, oversight, or in the frequency of ROE decisions that would justify the disparity in awarded returns between Alberta utilities and their U.S. counterparts.

65. The utilities submitted that the economic and business environments of Canada and the U.S. are highly integrated and therefore exhibit strong correlations across a variety of metrics. Over the long term, a reasonable investor would prudently expect comparable returns from the two countries. The utilities submitted that business risk, including regulatory risk, is comparable between the two countries and would not justify a risk differential for similar investments, either in terms of awarded ROEs or the allowed equity ratios.

66. As a result, some utilities argued, they are not attracting equity capital on their own merit, and this is contrary to the stand-alone principle the Commission has embraced. Because utility affiliates in the unregulated sector are earning higher returns, utilities are drawing on parent company support for capital to withstand the low level of returns allowed by the Commission. In this regard the Commission notes the following exchange between Commission Counsel and Mr. Edmondson of the ATCO Utilities:

[22] Rebuttal Evidence of Susan D. Abbott, Exhibit 283.03, page 21.

> We have at -- CU Inc. is the rated company within the group that does the debt financing for the ATCO utilities. CU Inc. is made out of ATCO Electric, ATCO Gas, and ATCO Pipelines as well as a company called Alberta Power 2000, which has our generation assets that were pre 1996 built that are in there and under PPAs [Power Purchase Arrangements].
>
> There is evidence in this testimony that – in this hearing that shows the CU Inc. credit metrics are being cross-subsidized by the nonregulated PPA-driven AP2K. So what we're saying is without the level of return that we're asking for here, there is a question of whether the financial integrity of the utilities can be maintained and on a stand-alone basis, they're not contributing their fair share to the development of CU Inc.'s credit status.[23]

67. To remedy the alleged defects seen in the allowed returns on the costs of equity in Alberta, the utilities proposed the ROEs and equity ratios set out in the following table.

Table 3. Utilities' Proposed ROE and Equity Ratios

	Recommended by Utility[24] (%)	Recommended by Utility[25] (%)
	Equity Ratio	ROE
Electric and Gas Transmission		
ATCO Electric TFO	38.0	10.5
AltaLink	38.0	11
ENMAX TFO	40.0	11
EPCOR TFO	40.0	11
ATCO Pipelines	43.0	12
Electric and Gas Distribution		
ATCO Electric DISCO	40.0	10.6
ENMAX DISCO	44.0	11
EPCOR DISCO	44.0	11
ATCO Gas	40.0	11
ATCO Gas for 2008[26]	40.0	11
FortisAlberta	42.0(+ 2)[27]	11
AltaGas	46.0	11
Retailers		
EEAI	42.0	11

1.11 Summary of Interveners' Position

68. Interveners representing various customers of the utilities argued that there is considerable evidence that investors in utilities have enjoyed superior returns during the period for which the annual adjustment formula has been in place. Dr. Booth, for CAPP, stated:

23 Transcript, page 1033, lines 1-15.
24 ATCO Evidence, Exhibit 50.01, page 5, Dr. Vander Weide Joint Evidence, Exhibit 57.04, page 37, Dr. Vilbert, Exhibit 58.02, page 24, ENMAX Evidence, Exhibit 55.01, page 6.
25 ATCO Evidence, Exhibit 50.01, page 5. (Also in ATCO Argument, Page 4), ENMAX Evidence, Exhibit 55.01, page 6, Vander Weide Joint Evidence, Exhibit 57.04, page 36, Vilbert AUI Evidence, Exhibit 58.02, page 24.
26 ATCO Argument, Exhibit 390.02, page 98.
27 42.0 percent Recommended by Dr. Vander Weide, 44.0 percent Requested by FortisAlberta to account for its (temporary) non-taxable status.

> ***For the whole period, 1988-2007 the average Statistics Canada ROE for Corporate Canada is 9.1 percent.*** What this means is that the average firm in Canada does not earn the level of ROE requested by most of the companies before the AUC and yet as the chart shows there is considerable year to year volatility in the overall earned ROE. This also normally implies higher risk. The upshot is that Corporate Canada as a whole earns lower ROEs and faces higher risk that the companies regulated by the AUC.[28]

69. The interveners generally proposed that, after setting the test year return on equity and capital structures they recommend, the Commission should reaffirm the use of the annual adjustment formula for a further period of up to five years. They argued that Canadian utility shareholders have not suffered under the current regime. On the contrary, they argued that Canadian utilities with BBB-level credit ratings and above are successfully accessing financing both domestically and in the U.S., and that there is no reason to believe the current global economic downturn will have a material effect on the long-run cost of equity for Canadian utilities. Dr. Booth stated:

> These bond market problems have affected the equity markets with the biggest drop in the TSX for almost 70 years. However, the recent price performance of utility shares during 2008 reinforces their low risk characteristics. It has to be emphasized that investors see utility shares as “defensive” and their share prices have been supported by the significant drop in interest rates that have occurred, since their rich dividend payouts become more attractive as interest rates drop. Consequently there is ***no*** indication that investors perceive Canadian utility stocks to be any riskier than my traditional beta range of 0.45-0.55; in fact the most recent estimates ending in 2008 indicate an average beta coefficient below this level.[29]

70. In general, the interveners argued that risks have not changed greatly since the annual adjustment formula was adopted. Market risk is low for the utilities due to uniformly low levels of competition, and low credit and supply risks. They argued that there exists substantive differences in the risk exposure for Canadian and U.S. regulated utilities. Interveners filed evidence to suggest that U.S. companies are subject to significantly greater degrees of business risk, including regulatory risk, than are Canadian utilities. The alleged discrepancies between Canadian and U.S. returns stem from differences in business risk, not from a deficiency in the formula methodology. Price performance of utility shares in 2008 reinforces their low risk characteristics and attractiveness to investors. Dr. Safir, for CAPP, explained:

> A primary criticism of the formula determined ROE has been the historic discrepancy between the returns that Canadian utilities have been allowed under their respective formulas compared to the allowed rates that U.S. utilities have been awarded. Typically U.S. utilities have received higher allowed returns on equity than their Canadian counterparts, and this gap has widened in recent years. Citing this comparison, critics have suggested that the Canadian formula driven ROEs have fallen short of the "fair return" standards as they are legally defined in the Canadian system.
>
> It should be noted that this criticism explicitly assumes that Canadian regulators expose Canadian utilities to the same degree of risk that regulators in the U.S. expect U.S. utilities to bear. While I believe it is true that the basic objectives of regulation are similar in Canada and the U.S., differences in the effective application of regulation between

[28] Revised Evidence of Dr. Booth, Exhibit 292.03, page 28.
[29] Revised Evidence of Dr. Booth, Exhibit 292.03, page 2.

these two jurisdictions results in substantive differences in the risk exposure of Canadian and U.S. regulated utilities. In fact, empirical analysis indicates that U.S. companies are subject to significantly greater degrees of regulatory and business risk.[30]

71. Interveners recommended, as a result of their analysis, significantly lower ROEs and lower equity ratios for the test year than did the utilities. Intervener recommendations are set out in the table below:

Table 4. Intervener ROE and Equity Ratio Recommendations

	Recommended by UCA & CCA[31] (K&R) (%)	Recommended by Calgary[32] (Booth) (%)	Recommended by CAPP[33] (Booth) (%)	Recommended by UCA & CCA[34] (K&R) (%)	Recommended by CAPP & Calgary[35] (Booth) (%)
	Equity Ratio			ROE	
Electric and Gas Transmission					
ATCO Electric TFO	33.0	<35.0		7.9	7.25
AltaLink	33.0	<35.0		7.9	7.25
ENMAX TFO	30.0			7.9	7.25
EPCOR TFO	30.0			7.9	7.25
ATCO Pipelines	42/34[36]		37/33[37]	7.9	7.25
Electric and Gas Distribution					
ATCO Electric DISCO	35.0			7.9	7.25
ENMAX DISCO	35.0			7.9	7.25
EPCOR DISCO	35.0			7.9	7.25
ATCO Gas	34.0	35.0		7.9	7.25
ATCO Gas for 2008	38.0[38]				
FortisAlberta	35.0			7.9	7.25
AltaGas	40/37[39]	40.0		7.9	7.25
Retailers					
EEAI	35.0			7.9	7.25

72. As can be seen from the above contextual overview and summary review of the positions of the parties in the Proceeding, the Commission has been presented with conflicting evidence from qualified experts, using a variety of analytical techniques, and in some cases the same techniques, to derive a range of recommended ROEs from 7.25 percent on an equity ratio of 33 percent, to 12 percent on an equity thickness of 43 percent, and 11 percent ROE on an equity ratio of 46 percent. The Commission was also faced with conflicting evidence on the nature, impact, and potential duration of the financial crisis. In the face of this conflicting evidence, the Commission was tasked with establishing a fair return for the companies it regulates.

30 Revised Evidence of Dr. Safir, Exhibit 292.04, pages 3-4.
31 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 6.
32 Calgary Argument, Exhibit 386.02, pages 12-13.
33 CAPP Argument, Exhibit 388.02, page 94.
34 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 9.
35 Booth Revised Evidence, Exhibit 292.03, pages 3, 86 and 112.
36 42.0 percent without NGTL Agreement, 34.0 percent with NGTL Agreement.
37 37.0 percent without NGTL Agreement, 33.0 percent with NGTL Agreement.
38 UCA Argument, Exhibit 387.01, page 97.
39 40.0 percent without weather deferral account, 37.0 percent without weather deferral account.

1.12 Decision Outline and Summary

73. In the sections of this Decision that follow, the Commission:

- reviews the legal requirements of the fair return standard,
- considers the application of the fair return standard to the evidence before it,
- considers whether to continue to determine a generic rate of return on equity and account, for company-specific risk through adjustments to the equity ratio,
- determines the rate of return on equity,
- establishes the equity ratios for each of the utilities in this proceeding,
- assesses the merits of continuing to employ an annual adjustment formula, and
- sets out its Order.

74. While the evidence relied on and the reasons for each of the Commission's determinations are detailed in subsequent sections of this Decision, the Commission summarizes its findings here.

75. The Commission discontinued its annual adjustment formula and has set a revised generic ROE for 2009 determined, on a *de novo* basis, independently of the existing adjustment formula, and based solely on the record of the proceeding. The Commission has set a generic ROE for 2009 and 2010 of 9.0 percent. The same ROE will be employed for 2011 on an interim basis.

76. The Commission has reviewed the models and approaches adopted by the various parties. Following the Commission's analysis, some of the CAPM and DCF results filed in this proceeding (including an analysis of the expected overall Canadian stock market returns) formed the primary basis for the Commission's ROE determinations. All of the Commission's analysis has been conducted in the context of, and having regard to, the uncertainties created by the current financial crisis that began in the third quarter of 2007.

77. The Commission has decided to change the equity ratios for each of the utilities by first increasing the equity ratio for each utility by two percentage points and thereafter adjusting upward or downward for sector-specific and company-specific factors.

78. In setting the equity ratios, based on the record of the Proceeding, the Commission considered: the risk to regulated utilities posed by the current credit environment, the evidence from credit metric analysis, and the evidence from an analysis of Canadian utility credit ratings and their corresponding equity ratios. The Commission also assessed, on the basis of the record of the Proceeding, the risk of each of the utility sectors and determined a relative ranking of risk for each sector. Company-specific matters were also examined. After considering and weighing all of this, the Commission set the equity ratios for 2009. As a consequence, while the Commission determined the equity ratios for each utility on a *de novo* basis, the analysis also focused on changes in risk since Decision 2004-052. The Commission believes that its awarded equity ratios will allow Alberta utilities on a stand-alone basis to target credit ratings in the lower A range. The following table sets out the awarded 2009 equity ratios for the utilities participating in this Proceeding.

Table 5. Approved Equity Ratios

Segment	Awarded Equity Ratio (%)
Electric and Gas Transmission	
ATCO Electric TFO	36
AltaLink	36
ENMAX TFO	37
EPCOR TFO	37
RED Deer TFO	37
Lethbridge TFO	37
TransAlta	36
ATCO Pipelines	45
Electric and Gas Distribution	
ATCO Electric DISCO	39
ENMAX DISCO	41
EPCOR DISCO	41
ATCO Gas	39
ATCO Gas for 2008	39
FortisAlberta	41
AltaGas	43
Retailers	
EEAI	39

79. The Commission has decided to suspend the application of the existing, or any, ROE adjustment formula. The Commission has set a generic ROE for 2009 and 2010 of 9.0 percent. The same ROE will be employed for 2011 on an interim basis.

80. The Commission examined several factors in applying the fair return standard in determining the ROE for 2009, including: Capital Asset Pricing Model (CAPM) results, Discounted Cash Flow (DCF) results, the Comparable Earnings Methodology, Return Awards by Other Regulators, Price-to-Book Ratios, Returns Available on High Grade Corporate Bonds, and the TSX Expected Market Return.

81. In 2011, the Commission will initiate a proceeding to consider the final ROE for 2011 and to consider whether to implement an annual ROE adjustment formula.

2 FAIR RETURN STANDARD

82. The authority and jurisdiction of a regulatory tribunal like the Commission to set rates for utilities is established by its governing legislation. The applicable pieces of legislation contain similar provisions that require the Commission to fix just and reasonable rates for the utilities that it regulates.[40] For example, the *Public Utilities Act* section 89 provides that the Commission may "… (a) fix just and reasonable … rates … which shall be imposed, observed and followed subsequently by the owner of the public utility.…" . The *Gas Utilities Act*, in a similarly worded section 36(a) also empowers the Commission to "fix just and reasonable … rates," as does the *Electric Utilities Act* section 121(1)(a).[41]

[40] Retail electricity "regulated rate tariffs" and retail natural gas "default rate tariffs" are regulated by the Commission but are subject to specialized legislative provisions that are not addressed in this Decision.

[41] See also Transmission Regulation A.R. 86/2007, as amended.

83. The rates allowed, and by implication the return on equity, must not be too low or too high. In *ATCO Gas & Pipelines Ltd.* v. *Alberta (Energy & Utilities Board)*[42] (*Stores Block*) the Supreme Court of Canada referred to academic authority on the principles of rate-making to state that "the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future,"[43] which "implies that shareholders should not receive 'too low' a return,"[44] however, "their returns should not be 'too high'."[45]

84. Both section 90(1) of the *Public Utilities Act* and section 37(1) of the *Gas Utilities Act* require the Commission to determine a rate base for a utility and to fix a fair return on rate base. Section 90(3) of the *Public Utilities Act* and section 37(3) of the *Gas Utilities Act* requires the Commission to give due consideration to all facts that in its opinion are relevant to fixing the fair return. Section 122(1)(a)(iv) of the *Electric Utilities Act* provides that the Commission when considering a tariff application for an electric utility must provide the owner of the electric utility with a reasonable opportunity to recover a variety of costs related to the capital invested in the utility including "a fair return on the equity of shareholders of the electric utility as it relates to the investment ….". While the words are slightly different among the several statutes, with respect to the return on the equity component of capital, the Commission considers the statutory requirements to be the same. The Commission must determine for each utility under its jurisdiction a fair return to be calculated on that portion of the capital invested in the utility determined by the Commission to have been financed by shareholder equity and provide each utility with a reasonable opportunity to realize that fair return.

85. Mr. Justice Rothstein speaking for the Federal Court of Appeal with respect to an appeal by TransCanada Pipelines Limited from a decision of the NEB described the cost of capital to a utility and the task required by the regulator in determining the cost of capital to be included with utility revenue requirement in the following manner:

> The cost of capital to a utility is equivalent to the aggregate return on investment investors require in order to keep their capital invested in the utility and to invest new capital in the utility. That return will be made in the form of interest on debt and dividends and capital appreciation on equity. Usually, that return is expressed as the rate of return investors require on their debt or equity investments.
>
> The rate of return on debt is not usually controversial. It normally consists of the weighted average interest rate for the test year on the utility's outstanding long-term debt. On the other hand, the rate of return on equity is often the subject of controversy and of much debate by expert witnesses.
>
> Unlike debt, where the interest rate payable is directly observable, the rate of return on equity cannot be accurately determined in advance. There are various methods experts use to estimate the rate of return on equity required by investors. The one adopted by the Board is an Equity Risk Premium methodology whereby the Board estimates a risk-free rate based on government bond rates and adds a risk premium to account for the risk associated with equity investment in a "benchmark" pipeline.

[42] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)* [2006] S.C.J. No. 4, 2006 SCC4.
[43] Ibid. at paragraph 62.
[44] Ibid. at paragraph 62.
[45] Ibid. at paragraph 62.

> Once the separate rates of return on debt and equity are established, they are consolidated into a composite rate of return on capital, based on the relative amounts of debt and equity in the utility's capital structure. In order to account for varying levels of risk between pipelines, the Board constructs for each pipeline a capital structure, i.e. the relative portions of debt and equity capital needed to finance its prudently acquired assets plus its working capital, on the basis of expert evidence. The greater the risk attributed to each pipeline, the greater the required equity component of its capital structure. That is because bond investors, who are more risk averse than equity investors, will not lend funds to an enterprise unless there is sufficient equity capital invested in the enterprise to give them confidence that they will be able to recover their investment from the assets of the enterprise in the event of default. …
>
> ……
>
> …. In cost of capital proceedings, the Board is entitled, on the basis of the evidence before it and the use of its own judgment, to choose a methodology for determining cost of capital and to estimate the cost of capital for a forthcoming year. Very often, the Board's estimate will not reflect the precise estimates of one side or the other or of one witness or another. Having regard to all the evidence, the Board will determine its own estimate.[46]

86. This Proceeding does not deal with the cost of debt component of the cost of capital specifically, rather it is the cost of equity and capital structure aspects of a utility's cost of capital that are relevant to this Decision. Mr. Justice Rothstein provided some further guidance with respect to the parameters in which the regulator must exercise its judgment in determining the cost of equity:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring that the Mainline's costs are not overstated. As respondents' counsel pointed out, there are numerous costing issues that may be subject to challenge. Questions may arise about, among other things, the allocation of costs between the Mainline and other divisions of the appellant; whether costs have been, or are being, prudently incurred; and whether the Mainline's compensation plans are reasonable. And, specific to this appeal, customers and consumers have an interest in ensuring that the Mainline's cost of equity is not overstated.[47]

87. The approach to determining a fair return on the equity component of invested capital in a regulated utility has ordinarily been referred to as the fair return standard. The fair return standard has been developed through case law, in particular three seminal decisions; the Supreme Court of Canada judgment in *Northwestern Utilities Ltd. v. Edmonton (City)*[48] and two decisions of the Supreme Court of the United States; *Bluefield Waterworks and Improvement Company v.*

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[46] *TransCanada Pipelines Limited v. Canada (National Energy Board)*, 2004 FCA 149 (*TransCanada Pipelines*) at paragraphs 6-9 and 58.
[47] Ibid. at paragraph 34.
[48] [1929] S.C.R. 186 (*Northwestern Utilities*).

Public Service Commission of the State of West Virginia[49] and *Federal Power Commission v. Hope Natural Gas Company*.[50]

88. The most authoritative source of guidance on the meaning of the term "fair return" is the Supreme Court of Canada's judgment in *Northwestern Utilities*. The Court was faced with the question of whether a predecessor board to the Commission had correctly set an allowed rate of return for a utility. In affirming the rate allowed, the Supreme Court first noted that the board had a duty "to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested."[51] The Court then set the rule on what a "fair return" would be:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[52]

89. Justice Smith, in a concurring judgment, also observed that:

> [t]he question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board.[53]

90. In *Bluefield* the Supreme Court of the United States was petitioned by a utility company that contended that its allowed rate of return was "too low and confiscatory."[54] In examining the company's claim, the Court answered the question of "[w]hat annual rate will constitute just compensation" by first observing that the answer "depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts."[55] It then held that

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties[.][56]

49 262 U.S. 679 (1923) (*Bluefield)*.
50 320 U.S. 591 (1944) (*Hope)*.
51 *Northwestern Utilities* at 192.
52 Ibid. at 192-193.
53 Ibid. at 199. The Supreme Court was faced with an appeal from a decision by a predecessor board to the Commission which lowered the allowed rate of return from the previously awarded 10% to 9% in light of changing conditions in the money markets. The Supreme Court affirmed the lowering of the rates allowed based on the decline in the interest rates.
54 *Bluefield*, at 692.
55 Ibid. at 692.
56 Ibid. at 692.

91. The Court qualified its ruling by noting that the company "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[57] What is required, however, is that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit to enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[58]

92. The Supreme Court of the U.S. revisited the question of what was a "fair rate of return" when it affirmed the rate of return allowed to a gas utility by the Federal Power Commission and noted that the purpose of the act governing gas utilities was "to protect consumers against exploitation at the hands of natural gas companies".[59] The Court clarified that the act's "ratemaking process", which required the "fixing of 'just and reasonable rates', involves the balancing of the investor and the consumer interests."[60] The company's investors, the Court explained, have "a legitimate concern with the financial integrity of the company whose rates are being regulated."[61] This means that there should "be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock."[62] The Court then held that:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[63]

93. The Court also noted:

> Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling.[64]

94. The three cases can be summed up to hold that a regulator when setting a rate of return must consider three factors, namely 'comparable investments,' 'capital attraction' and 'financial integrity.' Indeed, the AUC and its predecessor boards have accepted and employed these judicial pronouncements for many years and have also recognized the need for weighing the three factors based on evidence before it. For example, in 1977 the Alberta Public Utilities Board quoted with approval the following expression of the three factors:

> In developing his estimate of a fair return and a fair rate of return on common equity Professor Morrison stated that he had followed three "well known and widely employed" principles, namely,

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57 Ibid. at 692-693.
58 Ibid. at 693.
59 *Hope*, at 610 (1944).
60 Ibid. at 603.
61 Ibid. at 603.
62 Ibid. at 603.
63 Ibid. at 603.
64 Ibid. at 602.

> "1. That the investor should he able to obtain a return from his investment such as might alternatively be obtained from other investments of comparable risk and uncertainty;
>
> 2. The company should have sufficient income to enable it to attract additional capital as needed, without demanding that present investors dilute or subordinate their interests without compensation in favour of the, new investment;
>
> 3. That the company's financial integrity should not be impaired by reason of inadequate income."

> These principles are consistent with the principles, standards, criteria or tests which the courts in Canada and the U.S.A. and this Board have applied in determining the fair return or rate of return on common equity, although there are many variations in the approaches, methodology, techniques and judgments that have been used in applying those principles to a particular case.[65]

95. The Alberta Public Utilities Board went on to note in a manner similar to that expressed by Mr. Justice Smith in the *Northwestern Utilities* judgment:

> The Public Utilities Board Act requires the Board to fix a fair return on rate base; in doing so the Board finds it convenient and proper to consider a fair rate of return on each of the components of capital that is assumed will finance the rate base…[t]here is no mathematically or scientifically exact approach or method for the determination of the "fair return" on rate base which the Board can use, particularly with respect to the fair return on the common equity portion of capital which is assumed will finance a portion of the rate base. Any approach or method is largely dependent upon subjective judgments.[66]

96. In Decision 2004-052, the Alberta Energy and Utilities Board stated the following with respect to the fairness standard governing the rate of return:

> The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions. The Board concurs that the above decisions are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities.[67]

97. The Commission notes that other regulators have also applied these tests. For example the National Energy Board referred to the fair return standard in this manner:

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
> • be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);

[65] Alberta Public Utilities Board Decision E77121, Calgary Power Limited Rate Application 1976 – Phase I (Released: August 11, 1977) at pages 75-76.
[66] Ibid. at pages 82- 83.
[67] Decision 2004-052 at page 13.

> • enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> • permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).
>
> In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.[68]

98. In looking at the judicial guidance, and past regulatory practices, the Commission concludes that these three tests are the three factors that must be considered and examined when determining the fair return. What constitutes a fair return, then, is matter of judgment for the Commission, guided by these three factors and exercised after weighing all of the evidence and argument provided by the record. This was clearly articulated by Mr. Justice Smith in *Northwestern Utilities*, by the U.S. Supreme Court in *Bluefield*[69] and in *Hope*,[70] by the Alberta PUB in 1977 and most recently by Mr. Justice Rothstein in *TransCanada Pipelines*.

99. While there appeared to be a general consensus among the parties with respect to the three factors constituting the fair return standard in this Proceeding, there were some differences of opinion about the exact application of the fairness standard. As Calgary stated in its Reply Argument:

> There appears to be little disagreement between the parties regarding the standards for a fair return. Rather, it appears the disagreement is in the application of those standards and in the weight and probity of the evidence proffered by parties as to whether those standards have been met.[71]

100. On one hand, some of the parties seemed to assert that the test required that all three factors or tests be considered separately or were somehow independent. ATCO Utilities, as did other utilities,[72] argued that "[t]he allowed return must satisfy all three requirements of the fair return standard: financial integrity, capital attraction and comparable investment returns."[73] This legal position seemed to be adopted by their financial and economic expert witnesses in their testimony. For example, the following exchange occurred between the Chair and Dr. Gaske:

> Q. So looking at the three-part test, is it correct to say that if you have -- if you award -- if we were to award a rate of return that gave comparable earnings for comparable risk investments -- and let's say we accepted the U.S. evidence and we set it at that number, that we're automatically going to find ourselves in a situation where there's financial integrity assuming we have the comparable capital structure; but are we going to find ourselves automatically meeting the other two? Or is there a possibility that you could meet one of these but not the other two; or you could meet two and not the third one?

68 NEB Decision RH-2-2004, Reasons for Decision, TransCanada Pipelines Limited, Phase II (Released: April, 2005).
69 See note 19, *supra.*
70 See note 63 *supra*.
71 Calgary Reply Argument, page 7.
72 See for example the Written Argument of AltaGas, Exhibit 384 at page 10, the Written Argument of EPC, Exhibit 385.02 at paragraph 18 and the Written Argument of EPCOR, Exhibit 382.02 at paragraph 25.
73 ATCO Utilities Response to Undertaking at Transcript, pages 1556-1558, Exhibit 362.02 at page 2.

> A. DR. GASKE: I think it's being -- you need to meet all three and each one is a separate test so that it's possible to meet one and not the others.[74]

101. Similarly, during the same chain of questioning by the Chair, another witness Mr. Edmondson interjected:

> A. MR. EDMONDSON: I need to jump in here because I think it goes back to if up to be the Stanley Cup winner, you've got to win all four games; so it has to be in place --
>
> Q. But four out of seven, right?
>
> A. MR. EDMONDSON: Four out of seven, that's right; but until you get that fourth one in, until you have the third standard in there, I think you're offside on the fair return standard. ….
> But no, if it can be clearly identified that you're offside on one of the standards, then you're not meeting the fair return; and I think that's a problem. …[75]

102. CAPP expressed a different view. It argued that the three requirements of the fair return standard are "from an economic perspective, simply three ways of looking at the same thing."[76] Dr. Booth expressed this view in an exchange with Commission Counsel:

> There is one standard, there is just three ways of looking at it. In certain circumstances, for example, utility may not need to allow -- raise capital, and it's possible, in that situation, to give a rate of return that means they don't maintain their financial integrity, since they've already raised all of their capital.
> So each of these criteria are just parts of the same standard of being fair to the shareholders that have come up as a result of legal decisions in particular points in time. So if you give a fair rate of return then all these criteria are satisfied.[77]

103. CAPP went on to quote in its Argument from the *Hope* decision: "[r]ates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base."[78] CAPP stated:

> Has there ever been a time when a utility said that it was fair for it to get a meager return that was sufficient? Yet that is what *Hope* says.[79]

104. ATCO seemed to interpret the CAPP position and its citation to the *Hope* reference to the acceptability of "meager" returns as meaning that the Commission could provide a return that did not meet the comparability standard if the company was somehow achieving financial integrity and able to raise capital. ATCO sees this as an attempt by CAPP to support unreasonably low ROE recommendations by Dr. Booth. ATCO states:

[74] Transcript, page 1552, line 21 to page 1553, line 9.
[75] Transcript, page 1555, lines 1-12.
[76] CAPP Written Argument at paragraph 106, Exhibit 388.02.
[77] Transcript, page 3485, line 20 to page 3486, line 7.
[78] *Hope* at 605.
[79] CAPP Written Argument at paragraph 127, Exhibit 388.02.

> CAPP then makes the assertion that a return that is "meager" can still be fair. …
>
> ….
>
> The law requires that those returns be "as large a return" as it would receive on similar risk investments. CAPP's submissions in this respect must, therefore, fail. Dr. Booth's "meager" recommendations, therefore, fail to satisfy the Fair Return Standard.[80]

105. The Commission does not agree that the *Hope* case stands for the proposition that meeting only two parts of the fair return standard can be sufficient. The Court in *Hope* observes that if the three part test as described in the quotation is met, the fact that it might result in meager returns on a "fair value" rate base (one that is based on a higher current cost valuation of rate base that was rejected by the Court rather than the historical cost rate base that was accepted by the Court) does not make the finding invalid. A "fair value" rate base is not the same as a historical cost rate base.[81] *Hope* cannot stand for the proposition that meager returns that do not meet the three part test are sufficient to meet the fair return standard.

106. With respect to whether the three elements of the fair return standard is "three ways of looking at the same thing" as advocated by CAPP (among others) or three separate tests as advocated by the ATCO Utilities (among others) the Commission does consider that the three seminal fair return cases, as well as the observations of Mr. Justice Rothstein, all recognize that the three requirements of the fairness standard are inter-related. As Mr. Justice Rothstein observed, bond investors who are more averse to risk than equity investors will not lend funds to an enterprise unless there is sufficient equity capital invested. If the rate of return is not sufficient to allow equity investors in the utility the same return they could expect to earn if investing the "same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise" (the *Northwestern Utilities* comparability standard) a utility may not be able to attract sufficient equity investment in the enterprise without causing a dilution of the interest of present investors. As a result, it may be unable to attract sufficient debt investment at reasonable rates. Ultimately the company's financial integrity could be at risk which would harm shareholders and customers alike.[82] Similarly, if the Commission conducted a separate examination of rates of return awarded by other regulators and awarded such returns to Alberta utilities without regard to the effect of that award on financial integrity or the ability to attract debt capital, or the relationship of that award to comparable returns available in the market (whether they be higher or lower), the result could be unfair (either to the company or to customers). As noted above, Mr. Justice Rothstein in *TransCanada Pipelines* reinforced this conclusion when he stated:

> …if the Board does not permit the Mainline to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on

[80] ATCO Utilities Reply Argument, paragraphs 57 and 59.

[81] See Charles R. Phillips, *The Regulation of Public Utilities* 305-16 (Arlington: VA, 1988). The Commission is required by its certain of its enabling legislation to employ a historical cost rate base. The *Hope* case was decided at a time when the regulators were considering arguments favouring fair value rate base assessments versus historical rate base assessments.

[82] Mr Coyne referred to the impact of an unfair return by indicating that it would "…not provide sufficient financial metrics to satisfy the ratings criteria for an investment grade credit rating. Thus the return is deficient in meeting the minimum standards for financial integrity" and "…shareholders are left uncompensated for the increased risk associated with higher leverage." Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 70.

> equity. The tolls will therefore not be just and reasonable from the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring that the Mainline's costs are not overstated.[83]

107. The Commission notes with approval the following description by the ATCO Utilities of how the three factors or criteria of the fairness standard are assessed:

> In the ATCO Utilities' view, the assertion that the three-part test is "simply three ways of looking at the same thing" fails to recognize the critical fact that there are differing tests which help to "triangulate" a Fair Return. Each may have greater or lesser relevance depending upon the economic landscape upon which the tests are conducted. The frailty of reliance on only a single leg of the three legged stool for stability and reliability of the result over changing economic conditions should be obvious.[84]

108. After review and consideration of the legislation and the evidence, legal argument and case law referred to in this proceeding, the Commission reiterates its agreement that there are three criteria or factors to be employed in determining a fair rate of return. Each criterion or factor must be applied by the Commission when determining a fair return, but what constitutes a fair return (including capital structure) is a matter of judgment for the Commission, exercised after weighing all of the evidence and argument in the context of the facts observed in the marketplace.

109. In making these observations, the Commission does not consider that it is applying the three-part fair return standard differently than the Alberta Energy and Utilities Board has done in the past. Rather the Commission considers that it is consistent in both the description of the fair return standard and in the application of it in determining a fair return for Alberta utilities.

3 APPLICATION OF FAIR RETURN STANDARD

110. As discussed in the previous section of this Decision, the determination of a fair return on equity for Alberta utilities requires the assessment of three criteria: return on comparable investments, ability to attract capital and maintenance of financial integrity. As noted by Mr. Justice Rothstein in the *TransCanada Pipelines* decision cited above, the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is made even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors. This fact which has partially resulted from deregulation and unbundling of utility services, corporate reorganizations creating utility holding companies, holding companies owning a mix of regulated and unregulated business and utility acquisitions was referred to in the oral hearing as interposing a “dirty window” between direct market evidence on cost of capital and the true cost of capital for Alberta utilities. This effect was described in an exchange between Commissioner Lyttle and Dr. Booth:

[83] *Supra*, note 11.
[84] ATCO Utilities Reply Argument, paragraph 58.

> Q. Commissioner Lyttle: …I was just wondering why do we all only have utility holding companies and no regulated -- pure regulated utility companies listed? Is there an obvious reason for that or just a genesis of the market? I was wondering if you had a comment on that?
> A. DR. BOOTH: This has been a question I've been asked several times. Why is it that a regulated utility is more valuable part of a holding company than standing on its own? And my strong suspicion is that a freestanding regulated utility we wouldn't have the problem of looking at all the financial parameters through a dirty window. We would see directly how the market values the equity. We would see directly how the bond holders value the debt claims they've got on the firm; and you, as the regulators, could directly see what happens.
>
> The fact that we don't have any, and as I mentioned in my undertaking to Mr. McNulty, since I've been testifying we've seen the disappearance of a large number of pure regulated utilities. We've even seen -- we used to have a gas sub index, an electric sub index, a telco sub index on the old Toronto Stock Exchange 300. So even amongst the holding companies of gas, electric and pipeline companies and telco companies, you could get a better idea than now, but we lost Maritime Electric which was a pure electric utility on Prince Edward Island. We lost Island Tel in the same province. We've lost a lot of pure regulated utilities.
>
> In economic and financial terms, these are good firms to build a holding company around because they're stable companies generating huge amounts of cash flow generally if they're not sort of expanding their rate base.[85]

111. The fair return standard is a standard that was developed initially to provide guidance to regulators of stand-alone public utilities. At that time, generally, these utilities issued debt and equity directly to the capital markets and the market expectations were reasonably observable. Today the information required to make the judgments necessary to apply the standard to the utility operations is obscured by the presence of holding companies with a number of different businesses including unregulated businesses operating in competitive markets. This is the case not only in Alberta and other provinces but also in much of the United States. As a result, the Commission is left with the task of applying the fair return standard to Alberta utilities as if they were standing alone in the market, but with very little stand-alone evidence. A great deal of conflicting expert opinion on how to distill the vast amounts of primarily holding company evidence from Canada and the U.S. to determine a fair return for stand-alone utilities was presented in this proceeding.

112. Further complicating the determination of a fair return for Alberta utilities is the circularity created by a comparison of rates of return awarded to Canadian utilities on the basis of a formulaic approach and the significant percentage of government-owned utilities in Canada. As a result of these difficulties, utility companies urged the Commission to consider U.S. data on allowed rates of return and capital structure as well as U.S. market based returns in determining a fair return for Alberta utilities. Mr. Coyne, appearing for the ATCO Utilities stated:

> In Canada, the majority of utilities are bound by the same ROE formula, as are the utilities in Alberta, which is linked to the change in government bond yields. To evaluate the fairness of those ROE awards by looking to other Canadian utilities is analogous to looking in the mirror to compare your appearance to the reflection's. The potential for circularity of such a benchmarking analysis renders it, for the most part, meaningless as an independent source of comparability. Further, Canadian regulators have expressed

[85] Transcript, page 3544, line 7 to page 3545, line 11.

> concerns with certain methods of estimating ROEs, particularly the Discounted Cash Flow approach due to the limited number of publicly traded Canadian regulated utilities as well as insufficient analyst growth data. Looking to the U.S. helps to mitigate those data constraints.[86]

113. The utilities unanimously took the position that increasing globalization and integration of North American capital markets translated into a competition for capital with both debt and equity investors gravitating toward the highest return for similar risk investments wherever those returns were available in North America, if not globally. Utilities further submitted that the comparable investment, capital attraction and maintenance of financial integrity factors of the fair return standard all require the Commission when determining the fair return for Alberta utilities to consider utility return awards made by U.S. regulators trending toward an ROE of 11 to 12 percent on approximately 50 percent common equity.

114. The ATCO Utilities, supported by similar positions put forward by other utilities, particularly focused on the comparable earnings aspect of the fair return standard and contended that a comparison of average returns awarded by U.S. and Canadian regulators demonstrated the existence of a "fairness deficit" which has continued since 1996. This comparison showed that Alberta utilities have consistently been awarded lower regulated returns than their American counterparts. This differential has consistently widened under the existing ROE adjustment formula.

115. The utilities also claimed that the existing generic formula and capital structure of Alberta utilities were insufficient when assessed in light of the financial integrity factor of the fair return standard. In his Written Evidence, Mr. Coyne stated:

> **Q: DOES THE ALBERTA GENERIC RETURN OF 8.75 PERCENT SATISFY THE FINANCIAL INTEGRITY TEST?**
> A. No it does not. The returns generated by the generic allowed ROE in Canada and in Alberta, in many cases, do not provide sufficient financial metrics to satisfy the ratings criteria for an investment grade credit rating. Thus the return is deficient in meeting the minimum standards for financial integrity. As I have indicated previously in my testimony, the ratings agencies in Canada have allowed the Canadian utilities a higher degree of leverage than would generally be required of an investment grade utility company. Though the ratings agencies may be satisfied with the utility's ability to meet its debt obligations, the shareholders are left uncompensated for the increased risk associated with higher leverage.[87]

116. With respect to whether the existing generic formula and capital structure of Alberta utilities was sufficient when the capital attraction factor of the fair return standard was considered, Mr. Coyne stated:

> In addition, Canadian utilities are owned by diversified holding companies that are charged with the responsibility of attracting equity capital at the holding company level. The table below reveals that Canadian utility companies have much higher earned returns on equity at the consolidated level for purposes of attracting capital than those allowed for regulatory purposes.

[86] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 41.
[87] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 70.

Table 17: 2007 Consolidated Returns on Equity

	Canadian Utilities	Emera	Enbridge	Fortis, Inc.	TransCanada
ROE	15.96%	10.93%	14.53%	9.66%	13.99%

> The above returns on equity reflect what investors consider as they weigh the risk of these investments. These consolidated returns are commensurate with low-risk industrial companies shown earlier in my analysis. However, these returns are well above those allowed for regulated utilities in Alberta and thereby imply that the ability of the utility to attract new equity capital is aided by the diversification and higher returns of its parent.[88]

117. The utilities suggested that awarded returns, allowed capital structures and market based returns in the U.S. should carry significant weight in the Commission's deliberations despite certain regulatory differences, the few stand-alone utilities in the U.S. and the fact that many U.S. utilities remain vertically integrated (having generation, transmission, distribution and retail functions in the same corporate structure, unlike Alberta). The comparison to U.S. utilities is valid, experts for the utilities submitted, provided properly screened proxy groups are used in making comparisons. Mr. Coyne described his approach:

> I have developed estimates of generic cost of equity and recommended capital structure for Alberta's utilities based on the analysis I have conducted of electric, gas, and pipeline proxy groups, and the broader assessment of Canadian and U.S. utilities and their operating environments. These findings are summarized below. On balance, my recommendations are based on a synthesis of a considerable amount of financial, macroeconomic, industry and corporate information. I have factored in the differences between Canadian and US operating and financial environments through the careful selection of proxy groups, and utilization of Canadian specific data as appropriate. Additionally, I have considered the differences between the Alberta and Canadian operating and financial environments.[89]

118. In written Argument, the ATCO Utilities submitted that the fair return standard must be assessed in relation to a proxy of similar risk investments which includes U.S. as well as Canadian utilities like those included in the proxy groups selected by their expert, Mr. Coyne.

> As more fully detailed below, at the heart of that Fair Return Standard is the requirement that the regulator consider a proxy of similar risk investments from the universe of potential investments. Failure to consider, or even identify, a risk-adjusted proxy offends the legal requirement for determining a fair return. A comparison to that universe of other potential investments, without first differentiating those of comparable risk, is invalid. By its nature, the specification of similar risk companies requires the exercise of judgment. Since the derivation of similar risk companies from the universe of all potential equity investments is what the law requires, a proxy group of representative investments must be identified as a threshold step to the setting of a fair return. Careful comparison of the risk of each Alberta utility on a stand-alone basis relative to these similar risk benchmarks must be undertaken. It must be borne in mind, however, that "comparable" does not mean "identical".[90]

88 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, pages 73 and 74.
89 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, pages 80-81.
90 ATCO Utilities Argument, Exhibit 390.02 at page 15.

119. The Interveners cautioned against the use of U.S. utility proxy groups in drawing conclusions with respect to a fair return for Alberta utilities. Dr. Booth stated:

> Evidence from US natural gas and electric utilities indicates that while they generally have both higher allowed ROEs and more common equity than their Canadian peers, their financial strength in terms of bond ratings and market to book ratios is no better and usually worse. This implies that US utilities in general have higher business risk than Canadian ones. Only by specially choosing a ***sample*** of low risk US utilities can you form a sample of equivalent risk to the ***population*** of Canadian utilities. These low risk US utilities in turn have investment risk characteristics similar to Canadian utility holding companies.[91]

120. The utilities also pointed to the decision of the NEB in RH-1-2008 Trans Québec & Maritimes Pipelines Inc. (TQM Decision) as demonstrating the evolution of Canadian regulatory practice to include recognition of U.S. market-determined return data, as opposed to regulatory returns as informative and directly applicable to establishing a fair return for Canadian utilities.

121. Interveners urged the Commission to discount or dismiss the evidence and argument filed by the utilities with respect to the applicability of U.S. return data. Interveners maintained that differences in the regulatory and legislative environment between the two countries including differences in utility risk, test periods, length and frequency of negotiated settlements, integration of regulated and unregulated businesses, the mix of utility segments or functions within a single regulated utility, variability of utility earnings, currency, tax, fiscal policy, and the preference by U.S. regulators for the DCF method in determining utility returns, are substantial and verifiable reasons to disregard U.S. returns in determining a fair return for Alberta utilities, both historically and prospectively.

122. Interveners further contended that there exists a supportive Canadian regulatory environment which reduces risk for Canadian utilities and this is reflected in the consistently higher bond ratings for Canadian utilities despite historically lower awarded returns than their U.S. counterparts. Dr. Safir expressed this view as follows:

> The revenue protections afforded by the AUC to its regulated utilities are substantial and continue to provide them with a safety net that distinguishes their risk profile from comparisons with U.S. pipelines and LDCs.[92]

123. The treatment of evidence with respect to U.S. utility returns and capital structure became one of the most contentious issues in this proceeding. The utilities submitted that the concerns raised by the EUB with respect to the comparability of U.S. utility returns in Decision 2004-052 have either been eliminated entirely or substantially dissipated and that it is now time to correct the fairness deficit. Interveners took the position that the concerns expressed by the Board with respect to the use of U.S. data on utility returns remain valid today.

124. The Board's concerns were summarized in Decision 2004-052 as follows:

> In the Board's view, the Applicants did not demonstrate that the regulatory regimes in the two countries are sufficiently comparable that the Board should place significant weight on the return awards for US utilities. For example, the Board notes differences in

[91] Revised Evidence of Dr. Booth, Exhibit 292.03, page 3.
[92] Revised Evidence of Dr. Safir, Exhibit 292.04, page 4.

> legislation, public and regulatory policies, the higher prevalence of longer-term settlement arrangements, the federal/state jurisdictional divisions, the development of RTOs and other differences in the structure of regulated industrial sectors, and differences in national fiscal, tax and monetary policies. The Board notes AltaLink acknowledged that there are some differences in the Canadian and US electric industry structures that may impact some of the higher return and equity component awards in the U.S.
>
> Furthermore, the Board notes the recent acquisitions, at premiums to book value, by US companies of an interest in TransAlta Corporation's former distribution and transmission businesses. The Board considers these acquisitions, which are discussed further below, may be an indication that the regulated returns available in Alberta are not too low for US firms, relative to investment opportunities in their home country given all relevant circumstances.
>
> Directionally, the evidence on the awards available to US utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries.[93]

125. The utilities in this proceeding have forcefully asserted and have led expert evidence to show that the Board's reservations in Decision 2004-052 about the applicability of U.S. awarded rates of return to the determination of rates of return for Alberta utilities no longer apply. Moreover, the utilities have pointed to the NEB's TQM Decision as support for their positions. The interveners just as forcefully asserted and also led expert evidence that a change from the EUB's findings is not warranted. This sharp dichotomy of views provides a framework for a determination by the Commission of the applicability of U.S. return data in assessing a fair return for Alberta utilities. In the subsequent subsections of this Decision the Commission will review the following matters:

- What is the applicable market in which to assess the fair return standard for Alberta utilities?
- The comparability of business risk, including regulatory risk, of U.S. and Alberta utilities.
- Can U.S. utility allowed or market based return data be utilized in determining a fair return for Alberta utilities?
- Consideration of the findings of the NEB in the TQM Decision, with respect to the use of data on U.S. utility returns.

3.1 What is the Applicable Market in Which to Assess the Fair Return Standard for Alberta Utilities?

126. Alberta utilities must be able to attract capital, maintain financial integrity and have the opportunity to earn the return that they would receive on alternative investments of comparable risk. The question becomes, what is the applicable market in which to assess these elements of the fair return standard. All parties concede that there has been an increasing trend toward globalization of the world economy and an increased integration of North American markets. They disagree on, however, on the extent and implications of these developments.

[93] Decision 2004-052, page 26.

127. The utilities pointed to the deregulation of capital markets and changes in Canadian tax policy designed to increase the cross-border flow of capital including the elimination of the foreign property rule which had limited registered retirement and pension plans to no more than 30 percent foreign investments and the elimination of withholding tax on cross-border interest payments. They also pointed to the increased investment by Canadians in the U.S. market and the issuance of Canadian securities in Canada by U.S. investors, so called Maple Bonds, as evidence of the integration of the North American markets. The utilities suggest these developments clearly demonstrate that Alberta utilities must compete for capital with alternative investments of similar risk on a North American basis. The utilities also point to the recent financial crisis and the impacts on world markets as a result of issues primarily arising in the United States as further evidence of the tying together of the world's economies.

128. Dr. Booth appearing on behalf of CAPP acknowledged the higher degree of integration of the North American market but dismissed its impact on the determination of a fair return for Alberta utilities in the following discussion with Commission Counsel:

> Q. Some of the utilities in this proceeding have urged the Commission to take note of the globalization of the Canadian marketplace since the last generic cost of capital proceeding. They referred to it as the elimination of the foreign property rule for RSPs and registered pension plans, the elimination of withholding tax and cross border interest payments, and the advent of Maple bonds being issued in Canada in Canadian dollars by foreign issuers. The utilities also point to the TQM decision by the National Energy Board as recognition by a Canadian regulator that times have changed. Why aren't these positions valid?
> DR. BOOTH: There is a huge difference between saying there has been increased capital flows and saying that the world lives in a market where it's integrated. So there is absolutely no question we've got increased capital flows. If you ask me what percentage of my portfolio is in equity stocks and what percentage is in the US, I'd admit that I've got significant component in US stocks. And I think there is no question that investors in Canada have increased, diversified into foreign markets. The question, though, is how are those security prices determined? And in finance we have what we call the law of one price. If there is one worldwide market for oil, which there is, then there is basically an oil price and it's one global market. But that's not the same in the equity market. The equity markets are not fully integrated; they are not fully segmented the way they possibly were 50 or 100 years ago. We've always had capital flows in and out of the United States. The question is, Are the security prices in Canada determined in exactly the same way as they are in the United States, and how has this globalization affected the market risk premium and equity prices? Globalization diversification reduces risk, so we know that. In fact, a lot of the testimony the company witnesses refer to specifically refer to diversification. Diversification reduces risk, doesn't increase risk. So this globalization should result in lower risk premiums globally. So that's one very important feature. The other very important feature is that we live in a world of a partially integrated, partially segmented capital market. There has been research done to look at what determines the prices of Canadian securities. Some of them are determined more in an integrated market and some in a more segmented market, depending upon whether their characteristics appear desirable for international investors. In terms of utilities, the unfortunate fact is there is not much in Canadian utilities to appeal to foreign investors because they are basically close to bonds, in which case their investment characteristics don't make them attractive to foreign investors. And one of the information requests we asked the foreign security holdings in TransCanada has been dropping. The more you get closer to a pure utility, the less interesting the debts dock is for foreign investors. Foreign investors are interested in our resource stocks because they are interesting, they are valuable. They

> were very interested in Nortel and JDS Uniphase ten years ago because they were sort of unique. They are not particularly interested in utility stocks. So it's not as if the markets are completely integrated or completely segmented. They are partially integrated, partially segmented, and the most segmented part of the Canadian capital market are the very small stocks and stocks like utilities.[94]

129. The Commission agrees with the observations of Dr. Booth. While increased globalization and reform of tax and investment policies has increased the flow of capital across borders, the investment market for both Alberta regulated utility equity and debt remains almost entirely in Canada. With respect to the likelihood of Canadian investors looking for investments of a similar risk to Alberta utilities the Commission notes the observations of Dr. Booth in the following exchange with Commission Counsel:

> Q. Shouldn't, then, the returns on US utilities be a factor that this Commission should be very careful in terms of considering, in weighing the overall options that are available for Canadian investors?
> A. DR. BOOTH: No, because those returns that are allowed in the United States are factored into the prices of the utility holding companies in the United States. So the only way Canadians can access those rate of return is by paying the market price, and Canadian investors are going to look at that and say well, they've got to say 11, 12, percent rate of return but I'm having to pay two, three times book value and I'm exposed to the bigger regulatory risk. And I may to decide -- some people may decide they are going to make that investment, but all I'm saying is that if they are going to invest and take the foreign exchange risk and take the tax impediments, they are more likely to invest in pharmaceutical stocks, consumer discretionary stocks, which we don't have in Canada, than they are in utilities.
>
> There is always a global market for investment and there always has been. The question is what is the value of the imperfections, the frictions that disrupt these portfolios? And despite all of the relaxation of these barriers, investors portray what we call a home bias. Even the Americans have vastly more percentage in American stocks than American stocks account for in a world portfolio.
>
> Every single domestic market investors, by and large, suffer what we call this home bias, that they predominantly invest in the stocks in their own market. Part of it is familiarity. We even find regions in the United States that have a reasonable bias because the people are familiar, they are comfortable with it as well as these other barriers that we talk about.

130. While Canadian investors are now freer to invest anywhere in the world where they can maximize their return for comparable risk, the Commission agrees with Dr. Booth that Canadian investors considering investing in a regulated utility (assuming markets are efficient and priced for risk) are more likely to invest in Canadian utilities in order to achieve their expected return than in utilities outside Canada given the foreign exchange risk and possible tax differences that they would not be exposed to if they invested in Canada.

131. Support for these findings can be found in several statements from witnesses appearing on behalf of AltaLink and the ATCO Utilities with respect to their respective companies' preference to issue debt and equity in Canada.

132. The CFO for AltaLink, Mr. Bronneberg, had the following exchange with Commission Counsel:

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94 Transcript, page 3386, lines 24 to page 3389, line 15.

> Q. Well, sir, given that a lot of parties are involved in arbitraging between the US and Canadian markets, that parties are involved in hedging on a regular basis, that, to use your words, it works in the bond market because our cash flows are very predictable, why doesn't AltaLink do that?
> A. MR. BRONNEBERG: Why do we not look at US capital markets?
> Q. Yes, sir. Given all those advantages and the ease in which you can do it in the market?
> A. MR. BRONNEBERG: I've worked in the US capital markets before. I think that companies that have significant US dollar cash flows have natural hedges against currency fluctuations and would be able to match up their currency flows in the two countries with a reasonable degree of comfort. AltaLink has zero US dollar cash flows, and so it would have to go out and buy hedging positions in respect of all of its US debt repayment and US interest payment obligations. You can't do that for 30-year debt without assuming a significant amount of risk. I mean we've seen the Canadian dollar float from 60 cents to $1.10 in the last five to ten years. Those are pretty significant fluctuations and I think that exposes ratepayers to a significant amount of risk that we don't think is appropriate. As long as we have reasonable access to the Canadian debt markets -- and, you know, in our situation, we have owners who we look to contribute the equity that we need. There is absolutely no reason why you would go into the US capital markets.[95]

133. The following exchange occurred between Ms. Abbott, an expert witness appearing for AltaLink, Mr. Bronneberg and Counsel for the UCA:

> Q. Would you agree that, nevertheless, TransCanada's US financing creates currency exposure?
> A. MS. ABBOT: It does, but if they have US revenues, then that currency exposure is covered in -- to a certain extent. I haven't done an analysis of TransCanada, so I can't tell you how well that hedges exposure, but AltaLink would not even have that.
> Q. You would agree, subject to check, that TransCanada uses hedges to reduce or eliminate currency exposure?
> A. MS. ABBOT: Subject to check, sure, but that is still -- it's expensive. It's an exposure they have. It's something the rating agencies are not particularly sanguine about when a company who doesn't have any revenue in a particular currency borrows in that currency. It's a risk that they would look at as being unnecessary.
> Q. Does the management of AltaLink have the same views as Ms. Abbott?
> A. MR. BRONNEBERG: I think that the concept of AltaLink going into the US, regardless of the credit rating, is just unthinkable.[96]

134. Mr. Engen, an investment banker appearing on behalf of the ATCO Utilities when asked the question by Commission Counsel "[w]hen a Canadian utility looks for capital, it's primarily going to be looking to sources of capital from Canada and those sources of capital have an opportunity to invest anywhere in the world?", replied "[t]hat's correct."[97]

135. The Commission concludes that while the equity and debt markets for Alberta regulated utilities is primarily Canadian investors who primarily look to Canada when making utility investment decisions, the integration of the North American markets ensures that investments across North America are risk-adjusted in the market place in order to provide comparable

95 Transcript, page 220, line 4 to page 221, line 7.
96 Transcript, page 116, lines 3-22.
97 Transcript, page 1427, lines 4-8.

returns (foreign exchange and tax consequences aside) for investments in securities of similar risk. Accordingly, while there may be some degree of home bias on the part of the relevant investors as described by Dr. Booth and some concerns to individual investors related to foreign exchange and tax consequences, Alberta regulated utilities must, on a risk-adjusted basis, compete for their capital requirements with alternative investments of comparable risk across North America. Therefore, U.S. information on U.S. utility returns is relevant to a determination of the fair return for Alberta regulated utilities. If Alberta utilities must compete for investment across North America, the returns available to investors must be competitive enough to attract capital in order to ensure their financial integrity as a going concern.

136. While the Commission will accept U.S. data on rates of return, it is necessary to consider whether a distinction should be made between U.S. utility data on returns awarded by regulators (allowed returns) and U.S. data on expected market-based returns before considering the data as part of an examination of the fair return for Alberta utilities.

3.2 The Comparability of Business Risk, Including Regulatory Risk, of U.S. and Alberta Utilities

137. In order to determine the applicability of U.S. allowed return and expected market based return data the Commission must first examine whether the business risk, including the regulatory risk, of utilities in the two countries is similar enough to permit such a comparison. An investor's perception of business risk, including regulatory risk, of a regulated utility will be largely determinative of the return required by the market before an investor will invest in that utility. An assessment of the business and regulatory environment influences the perceived relative risk of a regulated utility compared to a utility in either a different business or regulatory environment and accordingly the comparability of their market returns.

3.2.1 Comparability of U.S. and Canadian Utility Business Risk Other than Regulatory Risk

138. In the Final Scoping Document[98] the Commission referred to the following definition of Business Risk:

> Business risk encompasses all the operating factors that collectively increase the probability that expected future income flows accruing to investors may not be realized, because of the fundamental nature of the company's business.[99]

139. Drs. Kryzanowski and Roberts refer to three main categories of business risk for utilities: market, operational and regulatory.[100]

140. Mr. Coyne noted:

> Operating or business risk represents the variability in company earnings that might occur due to changes in demand, costs of raw materials and labor, operating leverage, management's ability to execute its business strategy, competition for market share, and obsolescence of plant and equipment.[101]

98 Exhibit 36.01.
99 *New Regulatory Finance* by Roger A Morin, Public Utility Reports Inc., 2006, page 38.
100 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 18.
101 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 41.

141. Mr. Coyne undertook a comparison of U.S. and Canadian utilities with respect to operating or business risk and concluded:

> Based on my analysis, I conclude that there are no significant operating risks borne by the U.S. utilities that are not shared by the Canadian utilities. For purposes of this analysis, I view the U.S. and Canadian companies to be comparable, although not identical, in terms of operating risk.[102]

142. Mr. Coyne also noted that there are no macroeconomic factors such as dissimilarities between the U.S. and Canada in economic growth, inflation or unemployment which would warrant significant differences in investor expectations.[103]

143. Dr. Vander Weide noted:

> The risk of investing in electric and natural gas utilities is similar in the U.S. and Canada because: (1) U.S. electric and natural gas utilities rely on essentially the same electric and natural gas technologies to deliver their services to the public as electric and gas utilities in Canada; (2) the economics of electric and natural gas transmission and distribution is similar in the U.S. and Canada; and (3) U.S. electric and gas utilities are regulated under similar cost-based regulatory structures and fair rate of return principles as Canadian utilities.[104]

144. The Commission agrees that the business risks, other than regulatory risks, of the utility business are similar between Alberta utilities and counterparts in the U.S. With a few exceptions, utilities on both sides of the border utilize similar capital intensive fixed cost infrastructure and employ the same technologies in delivering their services, have similar operating and reliability standards and face similar commodity supply and demand dynamics. The Commission would also agree that while there may be some short-term differences in investor expectations between the two countries arising from macroeconomic factors given the relative impact of the current financial crisis on the U.S. and Canadian economies, in the longer run microeconomic factors should not result in an appreciable difference in investor expectations.

3.2.2 Comparability of U.S. and Canadian Regulatory Risk

145. The utilities generally took the position that although there are some differences in the statutory and regulatory framework governing utilities in the U.S. and Canada, most of these differences were small and did not materially impact the relevance of awarded returns in determining a fair return for Alberta utilities. What differences there are may result in some minimal increased regulatory risk for U.S. utilities but given that the regulatory principles were fundamentally the same in the two countries, these differences are insufficient to affect the return required by investors. The ATCO Utilities stated the following in written Argument:

> Utilities on both sides of the border are subject to the same cost of service regulatory model, which affords approximately the same level of regulatory protection. Any differences between the two regulatory models employed by either country are largely nuanced, are virtually indistinguishable to an investor or even a stakeholder in these

[102] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 46.
[103] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, starting at page 59.
[104] Written Evidence of Dr. Vander Weide, Exhibit 57.04, pages 14-15.

> regulatory proceedings, and ultimately would not result in a material difference in the investors' required rate of return for U.S. and Canadian utilities on the basis of national origin alone.[105]

146. The interveners submit that the Board made the correct decision when it discounted the usefulness of all American return information in Decision 2004-052. Interveners maintained that the Canadian regulatory environment is far more supportive of Canadian utilities than is the case in the United States. Alberta's proactive and supportive regulatory regime which reviews and sets rates generally every one to two years, the greater use of deferral accounts, legislative protections for electric transmission infrastructure development, the annual adjustment of rates under many negotiated settlement agreements and the rare disallowance of incurred capital or operating expenditures on the basis of a lack of either prudence or need, all substantiate this position.

147. Interveners also point to differences between Alberta and U.S. jurisdictions which respect to frequency of rate proceedings, length and frequency of negotiated settlements, integration of regulated and unregulated businesses, variability of earnings, the use of historical test years, the mix of utility segments or functions within a single regulated utility, currency and tax regimes, and the preference for the DCF method by U.S. regulators in determining utility returns as suggesting that U.S. utilities are subject to higher regulatory risk and therefore investors would expect higher returns. The interveners conclude that U.S. return data can not be used in any material way in setting a fair return for Alberta utilities.

148. Both interveners and the utilities appear to agree that there are many similarities in the regulatory principles employed in the U.S. and Canada. They also agree that there are regulatory differences between the U.S. and Canada. Where they are apart is with respect to the implications of these differences on the regulatory risk of U.S. utilities. The utilities consider any such differences are immaterial to the reliance of U.S. allowed returns in determining a fair return for Alberta utilities. The interveners disagree that these regulatory differences are sufficiently immaterial so as to permit a direct comparison of allowed returns. The Commission will explore these various differences in order to determine the impact to the risk faced by U.S. utilities when compared to Alberta utilities and therefore impact the comparability of their allowed returns.

3.2.2.1 Regulatory Philosophy

149. Mr. Coyne stated the following in his evidence with reference to the fairness deficit he identified between U.S. and Canadian awarded returns:

> Some argue that Canada's utilities are less risky or that the regulatory environment is more supportive as a basis for this gap. I have examined the operating and financial characteristics of the utility companies, the regulatory regimes in which they operate, the macro-economic environment, and the ability of utilities to recover expenses and adjust revenues in the U.S. and Canada. The results of this analysis repeatedly indicate that there is sufficient basis for comparison between the two countries and in my view, there are no appreciable differences in regulatory risk, financial risks, operating characteristics, tax structure, legislation, oversight, or in the frequency of ROE decisions that would justify the disparity that currently exists between the U.S. and Canadian ROE awards.[106]

[105] ATCO Utilities Argument, Exhibit 390.02, pages 63-64.

[106] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, pages 4-5.

150. As noted above, Dr. Vander Weide stated:

> U.S. electric and gas utilities are regulated under similar cost-based regulatory structures and fair rate of return principles as Canadian utilities.[107]

151. Dr. Safir on behalf of CAPP noted the arguments raised by the utilities that the basic regulatory philosophies between the U.S. and Canada were similar and accordingly the risks were fundamentally similar. He then observed that there also existed similar regulatory philosophies for the banking sectors in the two countries; however the recent financial crisis clearly demonstrated that regulatory oversight of the sector in the two countries was substantially different.[108] Dr. Safir summarized the differences in U.S. regulatory policy and approach which directly impacts business and regulatory risk for U.S. pipeline utilities which have no parallel in Canada:

> **Q34 Is it appropriate to compare the rates of return and equity thickness for U.S. pipelines to that of Canadian utilities in Alberta?**
> A34 No. There are significant differences in the business risk faced by U.S. pipelines and utilities in Canada which makes such comparisons inappropriate
>
> **Q35 What are the reasons for these differences?**
> A35 To a large degree this diversity stems from differences in pipeline regulation. This includes overt differences in the regulatory compact and balancing protections afforded to Canadian and U.S. pipelines. In addition, there are competitive differences between U.S. and Canadian markets. Although Canadian pipelines "interact" with U.S. markets, they operate primarily in the Canadian market, and are therefore subject to a different set of conditions. The differences as perceived by the market between U.S. and Canadian pipeline risks can be illustrated by using historical comparison of U.S. and Canadian pipeline circumstances in the 1980s-1990s. During this period, U.S. pipelines were subject to take or pay exposure, transportation brokering, and market-determined pipeline construction. As a result, over this same time frame, U.S. pipelines took real losses that were not experienced by Canadian pipelines. Pipeline ownership in U.S. carried higher risk then. It also carries higher risk now, as reflected in rates of return and equity bands.[109]

152. Dr. Safir also described the differences in regulatory philosophy relating to U.S. and Canadian local distribution companies (LDCs):

> **Q37 Why do you believe U.S. LDCs face more regulatory risk?**
> A37 It is clear that over the past two decades U.S. regulatory philosophy has placed an increased importance on the reliance of market forces as a substitute for hands on regulation. As a result, there have been more instances when regulators have adopted new and untested rules or policies that have called for more emphasis on market forces. This has led to unexpected consequences and, commensurately, an unexpected exposure to business risk.
>
> For example, the state of California jumped whole heartedly into electricity deregulation in the late 1990s, calling for divestiture of generation assets from LDCs. State regulators

107 Written Evidence of Dr. Vander Weide, Exhibit 57.04, pages 14-15.
108 Revised Evidence of Dr. Safir, Exhibit 292.04, page 19.
109 Revised Written Evidence of Dr. Safir, Exhibit 292.04 at pages 18-19.

> embraced their new plan without fully understanding its ramifications and effect on industry and consumers. As a result, the two largest electricity LDCs were left drastically vulnerable to market manipulation by wholesale power generators. This lead to bankruptcy for PG&E and widespread disruption in the provision of electrical services within the state during the 2000-2001 period.[110]

153. Mr. Coyne on behalf of the ATCO utilities suggested that events like the bankruptcy of PG&E in 2001 and the disallowance and deferral of hundreds of billions of dollars of stranded costs with the nuclear power industry in the 1970s and 1980s are examples of "rare events that could also occur in Canada" and that these "isolated instances are not sufficiently common to distinguish between U.S. and Canadian regulatory risks."[111]

154. Dr. Safir suggested that these examples of regulatory risk should not be discounted as historical aberrations and that they remain present in the risk assessment and return expectations of future investors. To illustrate this point, Dr. Safir referred to the "The Black Swan" event reference first discussed in testimony by Mr. Engen and explained by Dr. Gaske as follows.

> …about a year ago there was a best selling book called "The Black Swan, "and it was a best seller in finance circles. I don't know that it was a best seller in the general population, but it did make it into the book stores. And the idea behind "The Black Swan" is that people who looked backwards at risk and they try to measure it with the statistical methods, invariably miss the big things because the big things aren't things that you're expecting to happen, the things that come along that you don't really know about.[112]

155. Dr. Safir referred to and expanded on the Black Swan concept in his opening statement:

> Contrary to what you have been told, a black swan is not solely a future event. It is an outlier, which once experienced, can never be ignored as a future probability. It has a permanent impact on business risk. And here, once again, the higher incidence of such recent catastrophes as the financial market collapsed and utility bankruptcies in the United States is clear evidence that the U.S. regulatory policies create a framework where extremes are more likely to occur.[113]

156. The Commission agrees with Mr. Coyne, Dr. Vander Weide and the other proponents in the proceeding who suggest that the regulatory framework and the regulatory philosophies of both the U.S. and Canada are similar. The Commission agrees, however with Dr. Safir that there have been some significant differences in regulatory policy between the U.S. and Canada which have created additional regulatory risk for American utilities. The Commission further agrees that disallowances in the U.S. have had significant impacts on investor confidence and risk perceptions that once such events have occurred they will have ongoing effects on future investor expectations. While Mr. Coyne did not change his position that large disallowances in the U.S. were insufficient to distinguish regulatory risk between Canada and the U.S., he did observe in an exchange with counsel for CAPP, the following:

> So I think that without that, utilities are subject to risk. There are legitimate business risks associated with being in this business, and sometimes things do go wrong, as evidenced

[110] Revised Written Evidence of Dr. Safir, Exhibit 292.04 at pages 19-20.
[111] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 54.
[112] Transcript, page 803, lines 11-21.
[113] Transcript, page 3155, lines 7-15.

with PG&E in California, as evidenced by these nuclear cost disallowances. And those are risks that I think investors do take into account when they determine the cost of equity required to invest in these businesses.[114]

157. Differences in regulatory risk are further explored below.

3.2.2.2 Federal Energy Regulatory Commission

158. In considering the respective regulatory environments of the U.S. and Canada, the Commission considered the impact of segmentation of regulatory authority in the U.S. The Commission considers the differences in regulation between the federal regulator, Federal Energy Regulatory Commission (FERC), which regulates the interstate transmission of electricity, natural gas, and oil and state regulation, to be substantial enough to create additional regulatory risk for interstate electric and gas transmission utilities. These differences include FERC policies aimed at the encouragement of competition, incorporation of regulatory incentives to promote new investment and the encouragement of regional electric transmission. This view is supported by the following testimony by Dr. Vander Weide in addressing a question from Commission Counsel with respect to the comparability of FERC allowed returns:

> Q. And sir, could you just explain the difference you noted between how state regulators and the FERC come to conclusions with respect to rate of return?
> A. Well, it's not just the conclusions, it's not just how they arrive at their conclusions but it's the way the interstate markets are organized compared to the intrastate markets. The FERC has had a more aggressive policy of introducing competition into the electric transmission and especially the natural gas transmission markets, and so those markets tend to be viewed as being a little bit more risky than -- at least from the US perspective than the markets for intrastate electric and gas operations, which are more -- are local or regional in nature. So the costs of equity awarded at the FERC tend to reflect that difference in risk compared to state. I've only looked at the state allowed rates of return, and I haven't looked at the same kinds of companies that the FERC usually looks at when they consider pipelines or when they consider electric interstate transmission operations. To be conservative, I looked at the least-risky segments which were the state-regulated segments.
> Q. So, sir, are you then concerned or would you treat as suspect comparability analysis between FERC cost of capital results for electric and gas transmission utilities comparing that to Alberta utilities?
> A. Well, Alberta has transmission -- has special transmission risks associated with gas and electric. As I've indicated, to be conservative I decided to focus on just the lower risk parts of it, so I didn't attempt to use the FERC database to assess the risks of electric transmission and natural gas transmission in Alberta.
> Q. And again, sir, is that because you're concerned about comparability with Alberta utilities?
> A. You know, I didn't go far enough to assess the comparability. I just felt that it would be -- it would be a little more conservative approach to look at returns at the state level for the companies that -- either the allowed returns at the state level or the estimated returns for companies that were primarily involved with state-regulated activities.[115]

159. The observation that FERC regulation may lead to higher regulatory risk leads the Commission to discount allowed FERC returns from a consideration of the appropriate fair

[114] Transcript, page 837, lines 19-21.
[115] Transcript, pages 2183-2184.

return for Alberta utilities. As a consequence, the Commission is left with data relating to proxy groups involving smaller, mostly local, gas and electric distribution companies to consider.

3.2.2.3 Differences in Regulatory Practices

160. The Commission notes the attributes of utility regulation in Canada as enumerated by Dr. Booth which serve to reduce regulatory risk for Canadian utilities:

> The history of regulation in Canada is that when risks arise to potentially cause losses to utilities they are invariably transferred to rate payers as part of the dynamics of regulation. This dynamic is illustrated through:
> - the adoption of forward test years;
> - the removal of the commodity charge through fuel pass through for LDCs;
> - the removal of the merchant function;
> - the adoption of weather related deferral accounts;
> - increasing focus on the core service where the utility has market power;
> - the reduction in regulatory lag;
> - increased fixed charge component in rates
> - the adoption of ROE formula adjustments;
> - review of depreciation studies when stranded asset risk changes;
> - flexible hearings to review unique risks.
>
> All these policies have served to reduce the risk of regulated utilities in Canada. The fact is that regulation is a flexible process that moderates or shares these risks even if they do materialize to the extent that the regulated utility is rarely hurt. A case in point is Pacific Northern Gas (PNG), which I regard as the riskiest regulated utility in Canada.[116]

161. Mr. Coyne suggested in his evidence that many of the above features of Canadian regulation can also be found in the U.S.[117] Ms. McShane had the following discussion with Commission Counsel on this topic:

> Q. But in terms of comparability, I'm trying to figure out if you're suggesting that the US has moved more to be Canadian-like or Canadians have become more American-like; if that helps?
> A. MS. McSHANE: Well, I think that American utilities have probably adopted more -- additional mechanisms since 2004 than Canadian utilities have, in the aggregate.
> Q. So how does that enhance the comparability of the two?
> A. MS. McSHANE: Because I don't think that you could say today that there is a significant difference, material difference, in the degree of protection.
> Q. So, again, it sounds like you're suggesting that the American utilities have adopted mechanisms to reduce their risk that make them more like Canadian utilities in terms of deferral accounts and protections that they have available to them; is that what you're saying?
> A. MS. McSHANE: Yes, if I looked at the trend in the US, I would say there had been a trend over the past five years to adopting revenue decoupling; more adoption of weather normalization; adoption of riders to automatically add new plant to the rate base.[118]

116 Revised Evidence of Dr. Booth, Exhibit 292.03, pages 65-66.
117 Written Evidence of Mr. Coyne, Exhibit 50.01 Section 3, starting at page 54.
118 Transcript, page 1742, line 7 to page 1743, line 2.

162. Specifically with respect to the use of deferral accounts, the Commission notes the following comment of Mr. Coyne:

> Deferral accounts arguably reduce, to some extent, the risk of utilities because the accounts are intended to allow for the recovery of certain costs over a specified period of time. The deferral account helps the utility to stabilize the volatility of its quarterly cash flows and earnings, and to improve the utility's opportunity to earn its authorized rate of return. However, deferral accounts cannot fully eliminate the utility's risk because they are subject to a prudency standard.).[119]

163. The use of deferral accounts in Alberta and the additional legislative provisions requiring a utility to proceed with direct assign electric transmission projects and the legislative protections provided with respect to direct assign projects was the subject of an exchange on risk faced by Alberta TFOs between Mr. Frehlich, Chief Operating Officer of AltaLink and Commission Counsel:

> Q. And sir, aren't some of these business and operational risks mitigated by the history of backstopping arrangements that you've had with the AESO for projects like the last 500kV, the number of deferral accounts that deal with direct-assign projects, and the provisions of the transmission regulation, in particular, Section 39, which allows a TFO to include in its tariff, preconstruction costs incurred up to the -- incurred by the TFO with direct-assign projects, up to the issuance of permit and licence, including feasibility studies, engineering, purchase of materials and rights of way?
>
> A. MR. FREHLICH: Mr. McNulty, in response to your question. As it relates to, I'll pick a point in time, 2004, when we were last in the generic cost of capital process, the majority of the risk mitigation methods that you describe were already in place at that time. So there is not a material change from 2004 in that domain. The TFO has always been able to recover their prudently incurred costs, preconstruction and post-instruction, into the rate base. What we're describing here is essentially, as we go through this build there will be an increase in the execution risk for us as a business. And it's essentially to provide that, directionally, business risk is increasing compared to 2004. It's in support of Mr. Vander Weide's evidence that our fair return should be set at 38 and 11.
>
> Q. Sir, what I'm trying to understand is where the real risk is. If you have deferral accounts to cover your direct-assign projects that cover the actual versus the forecasted costs, if you have deferral accounts that deal with the changes in the forecast versus actual debt, if you have Section 37 -- sorry, 39 of the transmission regulation that allows you to recover preconstruction costs whether the project goes ahead or not, where is your risk other than the fact that you need to be prudent in what you spend?
>
> A. MR. FREHLICH: We use that term in such a short sentence that it seems like it's such a simple thing to do, to effectively execute billions of dollars worth of projects prudently. The fair return for our organization should be set based on the risks our business is exposed to; deferral accounts for direct-assigns have been placed prior to 2004. So the risk as a company that we're exposed to, is exactly that, the prudency risk; and it is the ability to effectively execute all of those projects prudently, is what the risk is that we're exposed to.[120]

[119] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 56.
[120] Transcript, page 287, line 23 to page 290, line 4.

164. In response to questions from counsel for CAPP Mr. Frehlich described his understanding of the protections provided to Alberta TFOs by section 42 of the *Transmission Regulation*[121] passed pursuant to the *Electric Utilities Act*:

> Q. So in that respect, AltaLink is special, if I can put it that way, in that it's treated somewhat differently than the non-TFO utilities before this Commission?
> A. MR. FREHLICH: I'm not going to speak for other utilities in front of the Commission. Our situation is as we've provided in our evidence around our credit metrics, and so as it relates to our credit situation, yes, we would see section 42 as providing the Commission with guidance around ensuring that we as a TFO in our situation have a stable investment climate and a steady stream of capital, especially through this build. And for us a stable investment climate relates to maintaining our A rating as we go forward through this build.

165. The Commission also notes that Mr. Coyne did not undertake a specific review of Alberta legislation before preparing his evidence and making his conclusions on the comparability of risks between U.S. and Alberta utilities as reflected in the following exchange with Commission Counsel.

> Q. Sir, I'm not quite sure I got the answer to half of the question. That is, did you look at the Alberta legislation?
> A. MR. COYNE: I did not specifically examine pieces of Alberta legislation. I had considerable discussion with the ATCO utilities, their representatives.
> I have been working with the Alberta AESO for some -- over a period of time in the context of WECC [Western Electricity Coordinating Council]. So I was aware of what the electric transmission policies and procedures were within WECC and within Alberta.
> So I would say it was more of a combined collection of analysis, expertise of those in the ATCO utilities in our team that we brought to bear.[122]

166. The Commission does not consider the fact that the actions of the utility in administering a deferral account must be prudent or that it must prudently manage its project costs materially alter the protections against business risk afforded to a utility in Alberta. Although, both Mr. Coyne and Ms. McShane have suggested that many of the deferral account provisions such as purchased gas adjustments, fuel cost recovery mechanisms, purchased power contract adjustments and weather normalization provisions afforded to Alberta utilities have some degree of corresponding protections in the proxy group of U.S. utilities, a thorough comparative analysis of the various deferral accounts and legislative protections available to Alberta utilities was not undertaken in support of this position. The Commission considers that there is ample evidence to demonstrate that the support provided by the legislative and regulatory context in Alberta materially reduces regulatory and other business risks of Alberta utilities when compared to the evidence proffered on U.S. utilities in this proceeding.

167. With respect to some of the additional attributes referred to by Dr. Booth and their use or lack thereof in the United States, the Commission notes the following exchange between Mr. Marcus appearing for the UCA and Commissioner Michaud:

[121] AR 86/2007, as amended.
[122] Transcript, page 1147, lines 6-17.

Q. …As you know, we've heard there is a lot of evidence from -- a lot of expert evidence on the record regarding U.S. and Canadian risk comparisons and opinions on that as to how the U.S. and Canada are -- according to Ms. McShane, for example, there is a narrowing of the gap between U.S. utilities and Canadian utilities from a risk perspective. And looking at your evidence, obviously you were not asked to comment on that, but you mentioned that Canadian regulation generally in Alberta, regulation specifically, makes greater use of forecasts, future test years than does American regulation, and then you go on to say this aspect of Canadian regulation renders it somewhat more supportive of utilities.

That's one glimpse into your thinking on that. I'm just wondering what your opinion is, generally, on the narrowing of the gap or where we're at today with respect to that issue.

Is Canada closer in risk to risk levels to US utilities or not?

A. MR. MARCUS: I'm going to start by saying when you look at financial analysis of utilities, you have to start by saying what is a utility. I know that's an elementary question, but many of the items that are called utilities by the U.S. financial services have large amounts of deregulated generations attached to them so that you don't have -- you have a limited number of pure play wires utilities. And when you look at, for example, an analysis of discounted cash flow of US utilities, you will find that the ones that have unregulated generation tend to have higher costs of capital, higher returns under the DCF method.

So you've got a little bit of a measurement problem there, but then when you turn to regulation, I would have to say honestly that there have been some moves in parts of the United States to relax things, but there is still the preponderance of the States are on historical test years, and some of them have some fairly stiff regulations on how you deal with historical test years.

As I say, there has been some relaxing. I know one of the States I work in has moved towards letting in information up to six months after the end of the historical test year. There are a few States that are future, but most of them still are historical.

There may be some areas where the United States is moving where Canada isn't on some of the issues such as decoupling of sales from revenues. Now, some utilities like it and some utilities don't. I think it's generally gas utilities like it and electric utilities are -- you know, some of them do and some of them don't.

I've seen a little more of that over the last few years. I think Alberta has taken a fairly large step in that direction, but with the weather normalization mechanism for ATCO Gas, that probably covers off about 80 or 90 percent of that decoupling risk on the gas company side.

So I would say there has been -- on the just pure regulatory side, there has been a little bit of a narrowing. I'm not sure I would take it as far as Ms. McShane has taken it.[123]

168. While U.S. utilities have benefited from the application of some of the attributes of Canadian regulation identified by Dr. Booth above and while the differences in regulatory practice between the U.S. and Canada may be narrower than they may have been at the time that the EUB last considered this matter, on the whole the Commission considers based on the evidence before it that these attributes are more pervasive in Canada and continue to suggest that Canadian utilities enjoy a more supportive regulatory environment and have less regulatory risk than their American counterparts. Further, the Commission considers that the reliance on historical test years and the DCF methodology[124] by the majority of U.S. regulators are further

[123] Transcript, page 3036, line 15 to page 3038, line 22.

[124] In response to a question from Commission Counsel Mr. Gaske stated at Transcript, page 1128, lines 12-16:

reasons for higher awarded ROEs in the United States. These conclusions are affirmed by the Commission's analysis with respect to credit metrics and bond ratings discussed below.

3.2.2.4 Credit Metrics and Bond Ratings

169. Mr. Coyne indicated that his research had shown that Canadian utilities generally have higher embedded debt costs and lower interest coverage ratios, despite having higher credit ratings compared to U.S. counterparts.[125] The higher embedded debt costs and lower interest coverage ratios flowed from the higher financial risk associated with the existing capital structures of Canadian utilities.[126] Mr. Coyne also noted that several utilities have insufficient financial metrics to support the credit rating that they had been given[127] and that some credit rating agencies maybe questioning the viability of some existing credit rating.[128] The ATCO Utilities conclude in their written evidence:

> …the evidence is clear that the individual ATCO Utilities could not maintain A credit ratings on a stand alone basis. The evidence indicates that it is the financial profile of Alberta Power 2000 which is the force behind the credit ratings of CU Inc. and which subsidizes the Utilities and thereby the financial risk of CU Inc.[129]

170. The concern about higher risk and shaky credit ratings for Canadian utilities was challenged by the interveners. In his opening statement, Dr. Safir summarized the differences in risk in the following manner:

> No one denies that allowed returns in Canada are below those awarded by US regulators, but it is simply inaccurate to infer from this that Canadian utilities do not receive returns commensurate with the risks that they face. The Canadian regulatory structure is simply more committed to insulating Canadian utilities from market forces. It provides more protective regulatory oversight. As a result, allowed returns in Canada should be lower than those in the United States.
>
> You have also heard that the basic regulatory model is similar in the United States and Canada. I would agree with that. However, it is important to realize that the application of this general regulatory model differs substantially between the two countries. The US system is more "hands off" at the federal level. It is more fragmented at the state level, and it is more experimental at both levels. These differences manifest themselves in straight forward and readily observable differences in the financial circumstances of Canadian and US utilities.
>
> You don't need to be a rocket scientist, you don't need to be a finance professor, and you don't even need to be an economist to notice these differences. One obvious one is the credit ratings afforded to Canadian utilities compared to US utilities. On average, Canadian utilities receive higher credit ratings than their US counterparts. This is exactly what you would expect if Canadian utilities faced lower business risks.[130]

"In the regulatory arena, in the United States before the various federal and state commissions, the DCF method is overwhelmingly favoured. In Canada, it's overwhelmingly not favoured. The capital asset pricing model seems to hold greater favour in Canada."

125 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 49.
126 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 49 and 51.
127 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 71.
128 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 55.
129 Written Evidence of the ATCO Utilities, Exhibit 50.01, Section 1, page 6.
130 Transcript, page 3153, line 21 to page 3154, line 9.

171. Also with reference to the possibility of credit downgrades suggested by Mr. Coyne, a related discussion occurred between the Chair and Dr. Vilbert, expert witness appearing on behalf of AltaGas. Dr. Vilbert referred to the acquisition of Canadian Bond Rating Services (CBRS) by Standard & Poor's (S&P) in October 2000 and the possibility that this would lead to downgrading of Canadian utilities.

> DR. VILBERT: I know that S&P when it took over CBRS had expressed some concern about that factor; that they were looking at the credit metrics and saying, gee, they would not ordinarily justify the A ratings that many Canadian utilities have, and they had, I think, initially put out a warning that there might be some downgrades. Subsequently that has not happened, to my knowledge.[131]

172. Mr. Coyne referred to a 2003 S&P report that followed the take over of CBRS which stated:

> Based on a wide-ranging reassessment of business and financial risk among Canadian utilities, Standard & Poor's is now questioning the appropriateness of placing exceptional analytical reliance on the positive influence of regulatory factors in its analysis of Canadian utilities.[132]

173. Mr. Coyne then went on state:

> I am not aware of any updates to S&P's broad assessment in this regard, but I would surmise that the growing gap between U.S. and Canadian ROE's and equity ratios would only serve to underscore these concerns.[133]

174. The Commission finds it very informative that despite concerns over the credit metrics of certain Canadian utilities by bond rating agencies, and in particular following the acquisition of a Canadian bond rating agency (CBRS) by an American firm (S&P), that the credit ratings have not materially changed. This appears to confirm the position expressed by Dr. Safir noted above that "[t]his is exactly what you would expect if Canadian Utilities faced lower business risks."

175. Another market indicator remarked on by Mr. Coyne in his evidence is the differences in beta[134] between U.S. and Canadian utilities. Mr. Coyne first makes the following observation about the differences in financial risk between Canadian and the U.S. proxy group of utilities:

> The capital structure of Canadian utilities is much more highly leveraged than for the U.S. proxy groups (41% common equity for Canadian utilities versus 55% for U.S. Gas and 49% for U.S. electric), which suggests that Canadian regulated utilities have significantly higher financial risk, attributable to the higher percentage of long-term debt carried on their balance sheets.[135]

176. Mr. Coyne then draws some conclusions with respect to beta differences:

> The Beta for Canadian utilities is lower than that for the U.S. proxy groups. This implies that Canadian utility equity returns move less with the broader market than do the U.S.

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131 Transcript, page 2435, line 23 to page 2436, line 4.
132 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 55.
133 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 55.
134 Beta is defined in Section 6.2 below.
135 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 51.

utility equity returns. This could be due to the imposition of a formulaic ROE in Canada, which is based solely on changes in the government long-bond yield that is not subject to broader market influences, unlike the returns for U.S. utilities which are set through application of various ROE estimation techniques such as the DCF and CAPM. Generally, a lower beta translates to lower risk for a diversified investor, in that returns of the subject company are more likely to move counter to the overall market and thereby provide a hedge against systematic market risk. However, there are several causes of low beta: illiquidity, irregular business cycle, constant earnings, or irregular earnings fluctuations, which will lower investor risk in the context of an investment portfolio, but may not represent intrinsically lower risk assets.[136]

177. Drs. Kryzanowski and Roberts dispute the conclusions drawn by utility experts with respect to the lower betas in Canada. In a discussion with Commission Counsel, Drs. Kryzanowski and Roberts referred to the lower interest coverage ratios in Canada discussed in Dr. Vander Weide's evidence[137] and the implication of lower betas in Canada.

A. Dr. ROBERTS: …So what Dr. Vander Weide's evidence is telling us is that in the States the utilities use less debt and, therefore, they have higher coverage ratios than utilities in Canada that have the same ratings. The utilities in Canada use more debt and they have lower coverage ratios. So why is that? Why do the rating agencies give the same rating to a utility with more debt in Canada than they would to a utility in the States with a same amount of debt? It must be that the rating agencies are seeing something that Dr. Vander Weide is not. And in our view what they're seeing is there's another component to risk besides their risk of the financial structure and that's the business risk. As we discussed yesterday, due to the regulatory environment in Canada, the business risk is lower. So the rating agencies look at the US utilities and say, yes they have higher coverage ratios, yes they have less debt than their Canadian counterparts. We're going to give the Canadian Utilities the same rating because we recognize they have lower business risk.
A. DR. KRYZANOWSKI: In fact, you could go one step further. If you then compare the betas, the measure of systematic risk, the betas are lower in Canada than they are in the US which indicates that the total risk of Canadian utilities is lower than the US.
Q. But, sir, when a utility goes to the BBB market in the States, they're still competing one on one with other risks in the -- other utilities seeking capital in the marketplace. And when an investor looks at the pretax interest coverage ratio between a Canadian utility and a US utility, where are they going to see the less risk for their money?
A. DR. ROBERTS: We agree with you, Mr. McNulty, that if the investor looks just at the pretax coverage ratio, they're going to recognize that the Canadian utility has got more leverage and that, by itself, taken in isolation, means that the Canadian utility has more risk. However investors are not going to look -- my point is -- they're not going to look only at that. They're going to look at all the relevant factors and the other relevant factors that we're pointing you to is while the Canadian utilities have got higher leverage which increases their risk, there are two other factors that reduce their risk: one is the lower business risk and the other is the total risk reflected in the beta.[138]

178. This view was further expanded in a discussion with Commissioner Michaud:

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[136] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, pages 52-53.
[137] See Written Reply Evidence of Dr. Vander Weide, Exhibit 282.01, starting at page 41.
[138] Transcript, page 2969, line 19 to page 2971, line 11.

> A. DR. KRYZANOWSKI: I'll discuss the total risk. If you look at the betas, they are quite a bit higher in the US, and if you look at Sharpe ratios which look at excess returns, in other words actual returns minus the risk-free rate divided by total risk, the standard deviation, they are quite comparable in both countries, okay?
>
> So the compensation, given the risk level, is fairly comparable in both countries which indicates that even on a total risk basis, the Canadian companies have lower risk.
>
> A. DR. ROBERTS: If I could just add finally, another way of looking at that, that we talked about before, to come back to it, to say the total risk is -- there is two pieces - the business risk and the financial risk. And of course, what you're referring to, regulation, would be a piece of business risk.
>
> So if we look at what else we know about it, and you have a debate about the business risk and the role of regulation, one way to get at it is to look at how bond rating agencies look at it because they look at total risk in order to determine their ratings. And we know they give comparable ratings, or slightly higher ratings, depending on which sample you look at, to the Canadian companies, which suggest that they think the total risk is similar to that of the US utilities or maybe even a little bit lower.
>
> The other factor we know is we can observe the amount of debt that utilities have by looking at the ratios, and we see the Canadian utilities, as many of the other experts in this hearing have already pointed out, they have more debt, higher leverage ratios. So if they have higher leverage ratios, they have more financial risk.
>
> So what we know is total risk is either the same or lower for the Canadian utilities; the financial risk piece is higher. So then if you back out, well, we don't know for sure, what we're debating is the business risk. So if the total risk is about the same and one piece of business risk is higher, the financial side, to us that suggests that the other piece that we're looking at, the business risk part, has got to be lower otherwise it doesn't add up. And part of that business risk is what you're asking about which is the regulatory part.[139]

179. Although the Commission acknowledges the argument that lower betas in Canada may be related to utility earnings being predicated upon a formula, the Commission accepts the overall conclusions of Drs. Kryzanowski and Roberts with respect to the implications of the lower Canadian beta and that it reflects both financial risk and business risk. If financial risk is higher in Canada, because of lower common equity ratios for Canadian utilities, then lower Canadian betas must mean that business risk, including regulatory risk, for Canadian utilities is lower than it is for U.S. utilities. If the beta is higher in the U.S. than in Canada for utilities, indicating that the business risk in Canada is lower (since the financial risk in higher), it suggests that the allowed returns should be lower in Canada.

180. The Commission also notes with approval Dr. Safir's analysis of risk between the U.S. and Canada and the greater variability in utility earnings in the U.S.

> Because of the differences in regulation between the two countries, U.S. pipelines are subject to comparatively more risk. Typically in Canada, tolls are adjusted annually, keeping pipeline earnings close to their allowed returns. However, in the U.S., rate hearings are much less frequent. Where rates are regulated infrequently, there is a higher probability that revenues and costs will diverge over time. Therefore, it is more likely that pipeline revenues will either exceed or fall short of costs. The ability and widespread practice of pipelines in negotiating and discounting rates, also contributes to more

139 Transcript, page 3039, line 5 to page 3040, line 20.

> variability in revenues. All these factors increase the probability that actual returns will either surpass or fall short of those allowable.[140]

181. Of import to utility credit metrics and therefore to the perceived risk of the utility is the presence or absence of construction work in progress (CWIP) being allowed into rate base. Mr. Coyne and Commission Counsel had the following exchange with respect to CWIP in rate base:

> Mr. McNulty: Putting the cost of equity aside for the moment, sir, is there a difference in regulatory protection of the utilities in terms of overall costs, operating costs, expansion costs, new project costs, situations that arise that are unexpected with the opportunity for a utility to come back to the regulator to cover unexpected costs vis-a-vis Canada versus the U.S.?
> MR. COYNE: I think the general regulatory principles are the same, and that is that reasonably incurred costs for the benefit of customers that provide assets that become used and useful to provide service to those customers, are recovered through rates. And those basic guiding principles are very much the same. But there are differences, jurisdiction to jurisdiction in the States, as there are province to province in terms of the numbers of programs and -- that specifically allow -- there are variations between jurisdictions without a doubt, but I think the same guiding principles are the same. One notable difference between the States and Canada is there is a much stronger prevalent of CWIP in the US than there is in Canada. There are 22 States in the US that currently allow CWIP and that's a fairly significant difference. It's nowhere near as common in Canada.[141]

182. The Commission would expect that the inclusion of CWIP in rate base would reduce the risk of U.S. utilities by improving their credit metrics compared to those in Canada, but yet this advantage does not appear to be sufficient to close the gap in comparative bond ratings or is offset by other risk factors.

183. In addition to the evidence referred to above, the Commission has also been assisted in arriving at the above conclusion that regulatory risk is higher in the United States than it is in Canada by the recent finding of the FERC which was referred to in the evidence of Dr. Safir[142] with respect to the inclusion of TransCanada in the proxy group it used to evaluate U.S. equity returns, stating:

> Also, TransCanada's Canadian pipeline is subject to a significantly different regulatory structure that renders it less comparable to domestic pipelines regulated by the Commission.[143]

184. In the context of understanding the ATCO Utilities proposal for an adjustment mechanism if the Commission decided to continue with a generic ROE with an annual adjustment formula, Commission Counsel explored with Mr. Coyne the comparability of utility bond indices and the proposal to use a Canadian utility bond index rather than a U.S. utility bond index in the adjustment formula. Mr. Coyne suggests a formula based on a 50/50 weighting of half of the change in Canadian A-rated 30-year utility bonds and recent ROE decisions.

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140 Revised Written Evidence of Dr. Safir, Exhibit 292.04 at page 16.
141 Transcript, page 1139, line 25 to page 1140, line 22.
142 Revised Written Evidence of Dr. Safir at page 14, Exhibit 292.04.
143 *Kern River Gas Transmission Co.*, Docket No. RP04-274, (Opinion No. 486-B) 126 FERC ¶611,034 (January 15, 2009), para. 60.

Q. Now, I'm hearing that in order to get a closer approximation of the cost of capital for Canadian utilities, you're relying on Canadian bond index to track that, not an American bond index to track that, despite the fact they are comparable in terms of risk and in cost to capital issues?
A. MR. COYNE: Yes, they track each other very closely. We have an index and a chart in my evidence in a shows that. But if I have an index -- if I had an index that measures Canadian utility cost of capital, I'm repeating myself, but it only makes sense to use it. To the extent that there is any potential for divergence, I have managed that by using the Canadian index.[144]

185. The Commission finds it of interest that Mr. Coyne indicated a preference for a Canadian utility bond index in an adjustment formula in order to remove the potential for divergence in the utility bond markets of the United States and Canada.

186. The relative risk between Canadian and American utilities from the perspective of credit rating agencies was the subject of an exchange between Ms. Abbott and Commission Counsel. Ms. Abbott, who appeared on behalf of AltaLink in the proceeding, has over 20 years of experience at Moody's Investors Service. Her responsibilities, for a portion of that time included utility ratings worldwide.

Q. Can I ask you, ma'am, to turn back to page 36 of your evidence. 57.05.
A. MS. ABBOTT: Okay.
Q. Page 36.
A. MS. ABBOTT: Yes?
Q. Line 732.
Q. The last line of that page, line 732, you indicate the average U.S. utility is rated BBB, and that there are no longer AAA companies?
A. MS. ABBOTT: Yes.
Q. Would that suggest that U.S. utilities are riskier, on average, than Canadian Utilities?
A. MS. ABBOTT: Yes.
Q. Could higher risk for US utilities justify a higher ROE and common equity ratio for US utilities when compared to Canadian Utilities?
A. MS. ABBOTT: It could, yes.
Q. Ms. Abbott, do you recall in the recent GTA hearing, you were asked by the Commission counsel about rating agency concerns about execution risk and the risk of having cost disallowed because they were found to be imprudent. And in your answer you refer to the State of Illinois. And if you'd like to turn it up, it's transcript volume 7, page 1083. At line 9.
A. MS. ABBOTT: Line 9. Okay.
Q. Your statement there was:

> "There is a very different regulatory scheme in the States than there is in the Province of Alberta and a different record in terms of costs."

Do you see that, ma'am?
A. MS. ABBOTT: Yes.
Q. What did you mean when you say the regulatory scheme in the US is very different than it is in Alberta?
A. MS. ABBOTT: Well, first of all, there is 50 different states and there are 50 different regulatory procedures in the States. And there are very few that have as many adjustment clauses as does Alberta; and there are none that I know of where companies are mandated to -- to build projects in the States.

144 Transcript, page 1076, line 25 to page 1077, line 12.

> The companies are the ones that generate that process. And they are the ones that go to the regulators and say: We would like to do this, that, and the other thing, as opposed to the regulator saying: You will do this, that and the other thing. So those are two of the big differences that I see.[145]

187. The Commission also notes the following exchange between Dr. Vander Weide and Commission Counsel with respect to this matter:

> Q. …Sir, starting at page 14 in question 27 and over to the top of page 15 you discuss your views that the risk of investing in electric and natural gas utilities is approximately the same in the US and Canada. You also make this point on page 34 when discussing the applicable common equity ratios. You point to the use of common technologies, similar economics, common cost of service regulation as support for your conclusions. You also dismiss the impact of deferral accounts in Canada suggesting that their impact is primarily on short term business risk which is more than offset by the financial risk Canadian utilities face because of lower common equity ratios.
>
> Have I summarized your position correctly, sir?
>
> A. Yes, and I would point out that I take a cut -- I make several comments about the risk and those are certainly some of those. I also, as I indicated yesterday in cross-examination, gave a more detailed analysis of the risks in response to several interrogatories, and I'm trying to find out which one it is.
>
> Q. Sir, I wasn't trying to capture every nuance of what you were suggesting but to capture the general flavour of what you're trying --
>
> A. Okay. The other place where I discuss the risks in more detail is in response to CAPP 003.
>
> Q. Thank you, sir. Sir, if Canadian U.S. utilities have similar business risk but different financial risk, wouldn't you have Canadian utilities to have lower credit ratings than comparable utilities in the United States?
>
> A. I'm looking at the question again. I'm not a credit rating expert, so it's difficult for me to comment on what credit ratings I would expect them to have, with the same degree of understanding as say a Susan Abbott would who has a lot of years of experience working for credit rating agencies.
>
> Based on the financial metrics alone, I would -- I am somewhat surprised that the Canadian utilities have slightly higher credit ratings than the US utilities because the financial metrics are quite a bit lower even for what I consider similar businesses. I don't know how to explain that, I'm just surprised at it, but I don't know how to explain it.[146]

3.2.3 Conclusions with Respect to Relative Risk and the Use of U.S. Data on Allowed Returns and Market Returns in Determining a Fair Return for Alberta Utilities

188. The Commission has characterized the fair return standard as three criteria or factors to be considered by the Commission when applying its judgment in determining the appropriate weighting to be given to the evidence before it in arriving at a fair return. In undertaking this effort, the Commission must assess the tools available to it and determine which ones are best suited to the purpose. The question that this part of the Decision has tried to address is: should U.S. data on allowed and market returns for U.S. utilities be considered in determining the fair return for Alberta utilities?

[145] Transcript, page 330, line 3 to page 331, line 25.

[146] Transcript, page 2157, line 9 to page 2158, page 25.

189. The Commission has had to assess a great deal of evidence with respect to the comparability of awarded returns for utilities in the United States. The utilities urged the Commission to consider the rates of return awarded by U.S. regulators on the basis that the risks faced by investors in utilities in Canada are comparable, if not higher than they are in the United States. If the risks are comparable for a proxy group of U.S. utilities then the awarded returns on that proxy group should be considered as a means of gauging the comparable return available to investors, the returns needed by Alberta utilities to attract investment and the returns required in order to maintain the financial integrity of Alberta utilities. Therefore, returns awarded by U.S. regulators should be used by the Commission in determining the fair rate of return for Alberta utilities. Canadian utilities must compete for capital from investors who are free to invest their capital where it will provide the highest return on comparable risk. Interveners have submitted that the regulatory risk and therefore the total business risk of U.S. utilities is not comparable to Alberta utilities and accordingly, the allowed returns on U.S. utilities should not be considered by the Commission.

190. In the sections above the Commission has reviewed the evidence relating to the comparability of risk and the use of U.S. data on allowed returns. For the reasons stated above, the Commission has determined to exclude return information on FERC regulated utilities. With respect to U.S. data on allowed returns for natural gas and electric LDCs and other state regulated utilities, the Commission finds, based on the evidence and analysis referred to above, that the regulatory risk faced by these U.S. utilities in general remain materially higher than the regulatory risk of Alberta utilities. As a consequence, the returns awarded by U.S. regulators for U.S. LDCs would be expected to reflect this materially higher level of risk leading the Commission to conclude that U.S. allowed returns should not be used in determining a fair return for Alberta utilities.

191. The Commission also appreciates the significance of investor perceptions of regulatory risk and to the extent U.S. utilities may be perceived to be riskier than Canadian utilities it will impact the return expectation of equity investors. The perception of risk of equity investors was discussed in the following exchange between the Chair and Dr. Vilbert:

> Q. …. If the perceived risk of Canadian utilities is lower than the perceived risk of American utilities, then the perceived potential for default is lower in Canada, which means that the perceived probability of the equity holders being stuck for the remainder is lower; is that right?
> A. DR. VILBERT: I think I followed the full train of what you said, and I think I also agree with it. There's a bunch of "ifs" in your hypothesis.[147]

192. Any discussion of allowed returns must necessarily consider both ROE and capital structure in assessing the comparability of utility returns in the U.S. and Canada. In this regard the Commission notes the following discussion between Ms. McShane and Commission Counsel:

> Q. Thank you, ma'am, but I'm just trying to understand whether or not the fact that management selects the capital structure that's then approved by the utility for U.S. utilities could be one influencing factor as to why common equity ratios are as high as they are and they have not come down with the absolute reduction in risk.

[147] Transcript, page 2440, lines 15-22.

> A. MS. McSHANE: Well, they're still within the ranges of what the guidelines are for their rating in their industries.
> Q. And, ma'am, do you think, again, could it be one influencing factor as to when you compare ROE or capital structure in Canada versus United States that because management selects the capital structure for U.S. utilities that it may be influenced to be higher in the United States as compared to having the regulator deem it historically in Canada? Is that one potential influencing factor to explain the differences?
> A. MS. McSHANE: I think the simple answer is yes. The deemed capital structures in Canada are lower than what they would be if management had more flexibility to choose them themselves.[148]

193. Ms. McShane's view that the equity ratio in the U.S. is likely higher as a result of the ability of management in certain U.S. jurisdictions to set the capital structure within a range acceptable to the regulator is a further differentiating point between regulation of U.S. and Canadian utilities and an indication that allowed capital structures for U.S. utilities should not be held up as representative of the capital structures required by Canadian utilities in order to satisfy the fair return standard.

194. The record does not support a finding by the Commission that allowed returns on U.S. utilities should be considered as evidence of comparable returns on investment, returns necessary to attract capital or returns required to maintain the financial integrity of Alberta utilities. Higher ROE and capital structures for U.S. utilities will inevitability translate into higher earnings for U.S. utilities. However, higher earnings for U.S. utilities does not translate into a denial of a fair return to Alberta utilities when the underlying risks of utilities in the U.S. and Alberta have been determined by this Commission to be materially different. The fair return standard requires the Commission to grant a utility as large a return on the capital invested as it would receive if it were investing an equal amount in an alternative investment of comparable risk.

195. Significantly, the Commission's finding on the comparability of risk and allowed returns between Alberta and U.S. utilities is supported, as referred to above, by expert testimony offered by some of the witnesses appearing on behalf of utilities in this proceeding and by recent findings by the FERC. Accordingly, U.S. data on allowed returns will not be considered by the Commission in determining a fair return for Alberta utilities.

196. Additionally, the Commission observes that allowed utility returns are not returns available to be captured by investors generally. During the hearing, Mr. Coyne was asked by Commissioner Lyttle about the distinction between the availability of allowed rates of return to investors as follows:

> So I have a problem with your fairness deficit because I can't really say that I can invest here versus I can invest there. your fairness deficit speaks about ROEs that are awarded by Board, but that's really not reflected in the ending market values except to determine earnings on those specific years. How much weight can I put on a fairness deficit where a lot of different things impact earnings?
> A. MR. COYNE: Good question. I agree with you. You can't buy --you, as an individual investor, can't really buy either of those. You have -- but this really relates to the awarded ROE, of course, for the utility so this is what the regulatory body is granting the original investor in this capital their return for continuing to have that capital invested in that franchise. That's right. Individual investors don't see this. What they

[148] Transcript, page 1747, line 13 to page 1748, line 8.

> see is the result of this as reflected through the marketplace with all of its other influences. This, of course, is an important driver because if you are a regulated utility, that is where your income comes from. It's that applied to your book value.

197. As noted in the *Northwestern Utilities* a fair return must allow a utility the opportunity to recover a return on capital invested as it would receive investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the utility. None of the original equity investor, a subsequent investor or a prospective utility equity investor can take its invested capital, or the capital it proposes to invest in one utility, and redeploy it to an investment in another utility <u>of comparable risk</u> (where a pure play utility investment is available) unless it is prepared to invest at market prices. The existing or prospective equity investor in one utility cannot take its capital and invest it in another utility at a price equal to the underlying book value of that other utility's assets where the market to book ratio is greater than one. Consequently, even if the Commission had determined that U.S. utilities were utilities of comparable risk to Alberta utilities, where the market to book ratio of a U.S. utility is greater than one, an investor in securities of that utility at market prices will not receive a return on its investment equal to the return allowed by that utility's regulator. Rather, an equity investor's total return on an investment made at market prices (putting aside foreign exchange risk and tax implications of any cross-border investments) will be a function of dividend policy and share price required by, or set in the market in light of the market's perception of the riskiness of the investment. Financial markets react quickly to adjust prices so that investors receive similar expected (risk adjusted) rates of return from all the various alternative investments.
Dr. Kryzanowski remarked on this result in response to a question from Commission Counsel:

> Q. And having gone through all those adjustments, even after those adjustments, is the stipulated return, for example, 12 percent on 50 percent common equity, is that even available to an investor, given that they have to pay market price to obtain the investment in the first place?
> A. DR. KRYZANOWSKI: Remember that that's an ROE, and an ROE is an accounting type of rate of return. Basically what you're interested in is market-based returns. So market prices will adjust to reflect the ROEs.[149]

198. Dr. Booth noted the following in an exchange with Commission Counsel:

> Q. Shouldn't, then, the returns on US utilities be a factor that this Commission should be very careful in terms of considering, in weighing the overall options that are available for Canadian investors?
> A. DR. BOOTH: No, because those returns that are allowed in the United States are factored into the prices of the utility holding companies in the United States. So the only way Canadians can access those rate of return is by paying the market price, and Canadian investors are going to look at that and say well, they've got to say 11, 12, percent rate of return but I'm having to pay two, three times book value and I'm exposed to the bigger regulatory risk.[150]

199. The Commission considers that while allowed returns awarded to selected proxy groups of utilities in the United States may be relevant in informing the Commission of how other regulators have assessed the fair return for utilities within their respective jurisdictions, allowed

[149] Transcript, page 3016, lines 3-11.
[150] Transcript, page 3395, lines 1-12.

returns cannot, in of themselves, be determinative of what a fair return for Alberta utilities should be given the inability of the investor to obtain the allowed return directly in the market.

200. The Commission considers that it must make a distinction between utility returns awarded by U.S. regulators and expected market based returns for U.S. utilities when considering the use of U.S. data in determining a fair return for Alberta utilities. Allowed returns, including both ROE and capital structure, are determined by a regulator after considering a number of factors including relevant overall factors like the applicable legislation and case law and individual factors that are specific to the utility, like the business risk of the utility. Also as noted above, the capital structure for U.S. utilities is frequently determined by management within a range acceptable to the regulator. The Commission has determined that returns awarded by U.S. regulators cannot be directly used in determining a fair return for Alberta utilities for the reasons provided above. Properly determined, however, expected market based returns in respect of a particular industry segment are a present reflection of the future return expectations of prospective investors given the perceived risk of that industry segment and the economy as a whole. The share price of the equity or the premium demanded on the sale of a corporate bond will adjust to meet these risk-adjusted investor expectations. Accordingly, expected market determined returns for U.S. utilities may be used on a market risk-adjusted basis in assessing a fair return for Alberta utilities, provided there is sufficient evidence to derive those expected market determined returns.

201. The Commission's conclusions with respect to the use of allowed returns as opposed to expected market based returns appears to be supported by the following exchange between the Chair and Dr. Vilbert, expert witness for AltaGas:

> Does this all come down to just let's do what the Americans do or is there something more for us to do here?
> DR. VILBERT: I think the short answer is no, I don't think that doing just what the Americans do is the right answer; and actually as I mentioned earlier, I've testified a lot in Canada and I've testified a lot in the United States and I think I heard Dr. Vander Weide say, yesterday, that cost of capital proceedings in the States take one to two days, whereas in Canada it's a longer process. I will also say that I prepare a lot harder when I testify in Canada than I do when I testify in the States because the questions are much more theoretical, they're much deeper questions. So in many ways, I think -- you know, it sounds like I'm being overly praising and I don't mean it to sound that way to sound that way, I'm just saying the Canadian regulatory process is pretty good and I think people, here, really are trying to get to the answer. I do believe, however, that the evidence from the States, particularly the sample companies from the States, has information to provide. I'm not as enamored of the idea of looking at the regulatory allowances in the States and saying that that should be some sort of a benchmark for you. It's certainly information, but I prefer, as a cost of capital expert, to rely on what the market is telling me as opposed to what other regulators are telling me. I do believe that the US market information is relevant to your deliberations and that that's one of the things that I think the NEB decision was positive about. It said look, let's look at the market information and the US companies provide us some information in that regard. After all, there are probably 15 to 30 gas LDC companies in the United States and there are substantially fewer than that in Canada. So that's a sample of companies you should access. But following -- not that you would – but following just slavishly along to what the Americans are doing, that doesn't seem to make any sense to me, particularly when it comes to allowed rates of return. You've got to consider the risks and so forth on your own. I do think it is a piece of evidence, though, when it comes to comparability the

> utilities in the States are being allowed more rate of return, higher rate of return on a higher equity thickness than their contemporaries in Canada.[151]

202. The Commission also finds support for its conclusions with respect to the use of expected market based returns rather than returns awarded by U.S. regulators in the following extract from a discussion between Dr. Vander Weide and the Chair:

> Well, in the US if one regulator looks just at what other regulators are offering, there is a circularity involved there. Rather than just looking at the -- cost of equity is determined in the marketplace. And let me give an example. Let's take Illinois versus California, say, and let's suppose the regulator in Illinois kind of ignores the market evidence and says "Let me just look at what the California regulators are doing and give the same rate of return as the California regulators." That would be circular, and I don't think anyone is suggesting that one ought to ignore the market evidence on the fair rate of return.[152]

203. In the above sections of this Decision the Commission has determined that sample proxy groups including U.S. utilities provided in evidence do have comparable business risk other than regulatory risk and that expected market determined returns in respect of these utilities may be informative to the Commission in determining a fair rate of return for Alberta utilities. Analyzing market based returns for U.S. utilities may be particular significant given the dirty window concerns with using data relating to Canadian holding companies discussed above (a concern also applicable to the U.S. data) and the circularity involved in setting allowed returns through a comparison to Canadian utilities whose returns have been set through a formulistic adjustment mechanism. As pointed out by Mr. Coyne and referred to above "[t]o evaluate the fairness of those ROE awards by looking to other Canadian utilities is analogous to looking in the mirror to compare your appearance to the reflection's."[153]

204. The Commission also notes the following comments of Dr. Vander Weide with respect to market based data on U.S. utilities:

> As discussed in my original filed evidence in this proceeding, there are several advantages to using U.S. utilities groups as comparables for the purpose of estimating the cost of equity for Canadian utilities. First, U.S. utilities groups include a significantly larger sample of companies with traditional utility operations than available Canadian utility groups. Second, reasonable estimates of expected growth rates are available for U.S. utilities, whereas the same data are not available for Canadian utilities. Third, reliable historical risk premium data for U.S. utilities are available for a much greater length of time than for Canadian utilities.[154]

205. In subsequent sections of this Decision the Commission will review the market based return data available on the record in respect of the sample U.S. utility proxy groups and employ this data in its CAPM and DCF determinations.

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151 Transcript, page 2430, line 11 to page 2432, line 8.
152 Transcript, page 2254, lines 8-19.
153 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 41.
154 AUC-Vander Weide-011(b), Exhibit 263.01.

3.3 TQM Decision

206. The utilities in this proceeding have urged the Commission to consider the findings made by the NEB in the TQM Decision on comparability of U.S. financial data in determining the fair return for Alberta utilities. The NEB concluded:

> In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's views that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008.[155]

207. Interveners have suggested that the TQM Decision is an anomaly when considered in the context of previous NEB decisions and previous decisions by the Alberta regulator.

208. The Commission notes that while the subsequent decision of the NEB on October 8, 2009[156] that the multi-pipeline return on equity formula will not continue in effect clearly indicates that the TQM Decision with respect to the NEB's views on the continued use of a generic ROE formula is not an anomaly, this subsequent decision does not address the use of U.S. utility return data.

209. The TQM Decision was focused on establishing the fair return for a single federally regulated natural gas transmission pipeline in the Province of Quebec which forms part of a highly integrated North American pipeline network and the NEB was specifically asked to consider the ATWACC[157] methodology for setting the TQM cost of capital for 2007 and 2008. In addition, the NEB in using a market-based ATWACC methodology considered not only the use of U.S. market data with respect to the cost of equity, but unlike the Commission in this proceeding, it also considered the market cost of debt and a market-value capital structure, using market-value weights for each capital component. The NEB concluded that this allowed it when considering capital structure to adjust for differences in financial risk among sample comparators to TQM and the market as a whole and to find that the embedded cost of debt was accounted for in the market-based ATWACC awarded, ultimately allowing TQM to establish its own capital structure.

210. The Commission is not considering the market cost of debt and a market-value capital structure and is not using market value weights for capital components. Rather, the Commission is determining the return on equity capital by setting an ROE and equity ratio that is then applied to the original cost rate base of each utility.

211. Noting these substantial differences in approach and scope, the conclusions reached by the NEB with respect to the use of U.S. market data in determining a fair return must necessarily be distinguished from the present matters to be determined by the Commission. This distinction being understood, it is nonetheless noteworthy to observe that while some of the conclusions reached by the Commission with respect to the differences in the regulatory environment between the U.S. and Canada and the comparability of returns are different than those reached by

155 TQM Decision, page 71.

156 National Energy Board Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94), dated October 8, 2009, File OF-Tolls-TollsGen-COC 01.

157 Defined in paragraph 52, page 12 above.

the NEB, several similarities exist with respect to the conclusions reached by the two regulators on the use of U.S. financial data in determining a fair return.

212. The NEB concluded and the Commission agrees that comparable investments do not necessarily have to be wholly or mostly regulated enterprises: non-regulated enterprises are generally expected to have higher risks than regulated ones and the presence of unregulated operations in a sample set of utility or holding companies implies that the estimated costs of capital are likely higher than they would otherwise be.[158]

213. The NEB concluded and the Commission agrees that there is a greater variability between actual and allowed earnings for U.S. utilities when compared to Canadian utilities due to higher short-term risks imbedded in the U.S. regulatory environment.[159]

214. The Commission notes that while the TQM Decision used U.S. litigated returns as a check[160] in conducting its ATWACC analysis it also placed principal weight on market derived returns from investments of similar risk rather than on allowed returns.

> The Board finds that financial market data results, properly derived, yield estimates of sample companies' true underlying costs of capital. This is because, in the Board's view, the underlying cost of capital is driven by investors' expectations as expressed in financial markets, and allowed returns are only one of many factors influencing these expectations.[161]
>
> The Board was informed by all of the financial market returns comparable groups presented as evidence by both parties. Consistent with the Board's decision in Chapter 4 to rely on a market-based ATWACC methodology, the Board has put principal weight on market-determined returns as opposed to regulatory returns. These market-determined returns of companies found to be of comparable risk to TQM, combined with the market-value capital structure, provide the Board with crucial information for determining TQM's cost of capital for 2007 and 2008.[162]

215. The Commission has determined to consider U.S. market based return data for U.S. utilities in its analysis. As mentioned above, the NEB indicated that the U.S. market based return data was "very informative for determining a fair return for TQM." The weight to be placed on U.S. utility expected market based return information by the Commission will be discussed in subsequent sections of this Decision when it addresses CAPM and DCF cost of equity estimates.

4 STANDARDIZED APPROACH

216. In Decision 2004-052, the Board adopted a standardized approach with a single generic ROE to be applied uniformly to all the utilities, and then adjusted for any differences in risk among the utilities by adjusting their individual equity ratios. The equity ratios for each company then remained constant throughout the generic cost of capital regime, since 2004. Throughout, the annual ROE was adjusted yearly using the annual adjustment formula.

[158] TQM Decision, page 71.
[159] TQM Decision, page 67.
[160] TQM Decision, page 69.
[161] TQM Decision, page 69.
[162] TQM Decision, pages 71-72.

217. The Board determined that its approach of adopting a common ROE and adjusting for differences in risk by adjusting capital structures recognizes the impact of leverage on the cost of equity and adjusts for differing investment risks. Decision 2004-052 stated that " … a common ROE approach can accommodate these differences, by adjusting for any material differences in investment risk that would otherwise occur, through an adjustment to the capital structure, or, in exceptional circumstances, through a utility-specific adjustment to the common ROE."[163]

218. Despite some reservations respecting the use of an annual adjustment formula, most parties were not opposed to the Commission adopting the Board's approach of establishing a generic ROE for all the utilities and adjusting the equity ratios of individual companies to account for individual risk. Indeed, all the companies, with the exception of the ATCO Utilities, requested the same ROE of 11 percent and differed only in their debt to equity ratio proposals.

219. The ATCO Utilities requested a range of ROEs from 10.5 percent to 12 percent on a variety of proposed company-specific capital structures. ATCO preferred that the Commission approve an ROE and capital structure individually for each ATCO utility and then allow for the ROE and capital structure to be adjusted, as required, at the time of each company's general tariff applications. Alternatively, ATCO argued that, following approval of the individual ROE proposals for each ATCO utility, "[r]esetting the capital structures to the ATCO Utilities' recommendations, and revising the adjustment formula to ensure changes in comparable returns can be tracked over time, provides greater assurance that a new Formula can withstand the challenge of consistently providing a Fair Return in the future."[164]

220. The Commission agrees with the Board that "implementation of a generic approach is in the public interest"[165] because a generic approach improves efficiency of the regulatory process in Alberta, provides for greater consistency among utilities, and greater certainty and predictability of utility returns. Administrative efficiency in dealing with cost of capital evidence in rate proceedings was clearly an impetus for the Board and parties to consider a generic ROE formula approach and a single proceeding for setting capital structure for all utilities. The Commission considers that the proliferation of regulated companies caused by electric and gas deregulation, unbundling, and corporate reorganizations that influenced the Board to adopt a generic approach remains a compelling reason to continue with that approach.

221. Consequently, in this Decision, the Commission will approve a single generic ROE to be applied uniformly to all the utilities, and will adjust for any differences in risk among the utilities by adjusting their individual equity ratios.

5 2009 RETURN ON EQUITY

5.1 Introduction

222. To satisfy the fair return standard, the Commission is required to determine a fair return on equity for the utilities. The Commission was presented with a significant body of evidence on the tests to be considered when determining the fair ROE for 2009, a number of opinions on the proper methodology to be employed for many of the tests and, as a result, a wide range of proposed ROEs. Briefly, the record of the proceeding included evidence to support ROE

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163 Decision 2004-052, page 14.
164 ATCO Argument, Exhibit 390.02, page 112.
165 Decision 2004-052, page 11.

estimates based on the Capital Asset Pricing Model (CAPM), the Discounted Cash Flow Model (DCF), the comparable earnings test, ROE awards by U.S. regulators, ROE awards by Canadian regulators, market- or price-to-book values, returns on high grade bonds, returns arising from negotiated settlements, and the return expectations from pension and investment managers. In addition, the Commission heard that specific adjustments to ROE might be required for some utilities. On the strength of this evidence, the Commission was presented with the following recommended ROEs for the utilities.[166]

Table 6. Summary of ROE Recommendations[167]

	2009 Formula Based (%)	Recommended by Utility[168] (%)	Recommended by UCA[169] (K&R) (%)	Recommended by CAPP[170] (Booth) (%)
Electric and Gas Transmission				
ATCO Electric TFO	8.61	10.5	7.9	7.25
AltaLink	8.61	11	7.9	7.25
ENMAX TFO	8.61	11	7.9	7.25
EPCOR TFO	8.61	11	7.9	7.25
ATCO Pipelines	8.61	12	7.9	7.25
Electric and Gas Distribution				
ATCO Electric DISCO	8.61	10.6	7.9	7.25
ENMAX DISCO	8.61	11	7.9	7.25
EPCOR DISCO	8.61	11	7.9	7.25
ATCO Gas	8.61	11	7.9	7.25
FortisAlberta	8.61	11	7.9	7.25
AltaGas	8.61	11	7.9	7.25
Retailers				
EEAI	8.61	11	7.9	7.25

5.2 Capital Asset Pricing Model

223. The capital asset pricing model is a well-accepted and theoretically-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return. CAPM is based on the principle that investors need to be compensated in two ways; for the time value of money and for risk. In the model, the time value of money is represented by the rate that compensates the investor for placing money in a risk-free investment over a period of time (the risk-free rate). The second part of the model considers risk and estimates the compensation that the investor needs for taking on the risk that the expected return will not be realized. This element of risk is calculated by taking a risk measure (beta) based on the statistical relationship between the historical returns for the investment security relative to the historical returns for the market as a whole, over time. Beta is a risk measure that describes how sensitive the expected return of a security is to the market. Hence, CAPM calculates the expected return for a security as the rate of return on a risk free security plus a risk premium.

[166] The 2009 formula-based calculation is also shown.
[167] The utilities' and interveners' ROE recommendations were made in conjunction with their equity ratio recommendations.
[168] ATCO Evidence, Exhibit 50.01, page 5. (Also in ATCO Argument, Page 4), ENMAX Evidence, Exhibit 55.01, page 6, Vander Weide Joint Evidence, Exhibit 57.04, page 36, Vilbert AUI Evidence, Exhibit 58.02, page 24.
[169] Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 9.
[170] Booth Revised Evidence, Exhibit 292.03, pages 3, 86 and 112.

224. Dr. Booth explained the use of CAPM in his evidence as follows.

> Why the CAPM is so widely used is because it is intuitively correct. It captures two of the major “laws’ of finance: the time value of money and the risk value of money…the time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm’s risk. As long as the market risk premium is approximately correct the estimate will be in the right “ball-park.” Where the CAPM gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory.[171]

225. Evidence to support proposed ROEs based on an application of CAPM was provided by Dr. Booth, Drs. Kryzanowski and Roberts, Mr. Coyne, and Dr. Vilbert. Dr. Vander Weide did not provide a CAPM estimate but he did propose that the appropriate beta for utilities is 0.93, based on data from the U.S. market.[172]

226. The following table sets out the recommended individual CAPM components and resulting ROE levels for each of the experts that presented evidence on CAPM.

[171] Booth Revised Evidence, Exhibit 292.03, page 70, lines 14-24.

[172] Transcript, page 2173, line 17 to page 2174, line 12 and Dr. Vander Weide Rebuttal Evidence, Exhibit 282.01, page 25.

Table 7. CAPM Recommendations

Expert Witness	Risk-free Rate (%)	MERP (%)	Market Return	Beta	Utility Risk Premium (%)	Flotation Allowance (%)	ROE (%)
Dr. Booth	4.25[173]	5.0[174]	9.25	0.50[175]	2.5[176]	0.50[177]	7.25[178]
Drs. Kryzanowski & Roberts[179]	4.75	5.1	9.85	0.52	2.65	0.50	7.90
Mr. Coyne U.S. Gas DCs[180]	4.44	6.25[181]	10.69	0.80	5.0	0.50	9.95
Mr. Coyne U.S. Elec. DC	4.44	6.25	10.69	0.81	5.1	0.50	10.0
Mr. Coyne N.A. Gas Trans	4.32	6.25	10.57	0.90	5.6	0.50	10.47
Mr. Coyne Canadian Utilities	4.13[182]	6.25	10.38	0.72	4.3	0.50	9.14
Dr. Vilbert Canadian Utilities[183]	4.5	5.75	10.25	0.63	3.62	0.50	8.6
Dr. Vilbert U.S. Gas DCs[184]	4.5	5.75	10.25	0.78	4.49	0.50	9.5
Dr. Vilbert U.S. MLPs[185]	4.5	5.75	10.25	0.57	3.28	0.50	7.9

227. Dr. Booth based his CAPM analysis on Canadian data only, as did Drs. Kryzanowski and Roberts. Mr. Coyne provided multiple CAPM analyses based on U.S. and Canadian data, as did Dr. Vilbert. With respect to Dr. Vilbert's CAPM analysis for his U.S. proxy groups, the Commission will not consider his analysis of Master Limited Partnership (MLP) pipelines. Dr. Vilbert used his MLP pipeline proxy group to derive a recommended ROE for NGTL. Now that the Commission is no longer required to establish a fair return for NGTL, the Commission finds that this proxy group is not representative of the companies at issue in this proceeding. In addition, the Commission observes that Mr. Coyne, on behalf of the ATCO Utilities (including ATCO Pipelines) did not include MLP pipelines in his proxy groups. Finally, the MLPs have structural differences and investor tax implications which differentiate them from most Alberta utilities.

173 Booth Revised Evidence, Exhibit 292.03, page 18.
174 Booth Revised Evidence, Exhibit 292.03, page 82, Market Risk Premium higher than the experienced premium over almost any period but accounts for the unexpectedly high returns on bonds in recent decades.
175 Booth Revised Evidence, Exhibit 292.03, pages 79 and 82.
176 Booth Revised Evidence, Exhibit 292.03, page 82 (and 5% times 0.50 = 2.5%).
177 Booth Revised Evidence, Exhibit 292.03, page 86.
178 Booth Revised Evidence, Exhibit 292.03, page 86.
179 Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 9.
180 Exhibit 50.01, Evidence of James M. Coyne, Table JMC-05.
181 Exhibit 50.01, Evidence of James M. Coyne, pages 29-30. Market risk premium based on the average of the experienced market risk premium of 7.1 percent in the U.S. from 1926 to 2007 and 5.4 percent in Canada from 1936-2007.
182 Exhibit 50.01, Evidence of James M. Coyne, page 27, based on October 2008 Consensus Forecasts of the 10-year rate plus the September 2008 average spread between 10-year and 30-year government of Canada bonds.
183 Exhibit 52.02, NGTL Evidence, Dr. Vilbert. Table MJV-10.
184 Exhibit 52.02, NGTL Evidence, Dr. Vilbert. Table MJV-20.
185 Exhibit 52.02, NGTL Evidence, Dr. Vilbert. Table MJV-26.

228. In considering the evidence on CAPM, the Commission reviewed the remaining proposals on the individual components of CAPM, as well as the overall ROE levels based on the CAPM approach.

5.2.1 Risk-Free Rate

229. The CAPM analysis starts from a forecast of the risk-free rate. Parties differed on their recommended forecast of the risk-free rate. Dr. Booth based his forecast on ten-year long Canada bond yields forecasted by Consensus Economics Inc. and added 0.89 percent for the current spread between the thirty and ten year bond. This resulted in a 4.00 percent forecast to which he added 0.25 percent based on his judgment that the economy will recover more quickly which will cause interest rates to increase. He submitted that his resulting 4.25 percent estimate "is more in line with that of the Bank of Canada."[186] Given that Dr. Booth's forecast aligns with that of the Bank of Canada, the Commission accepts it as a reasonable forecast.

230. Drs. Kryzanowski and Roberts based their forecast of the risk-free rate on the long Canada yield of 4.36 percent adopted by the National Energy Board, which was based upon the Consensus forecast, in setting its allowed ROE for 2009,[187] but added 40 basis points "to normalize this yield for the effects of the current easy money monetary policy designed to stimulate economic activity due to the current global credit and economic crises."[188] They rounded their result to a forecast of 4.75 percent, noting that the same result was found in a recent forecast by TD Economics[189]. The Commission does not agree with the 40 basis point adjustment proposed by Drs. Kryzanowski and Roberts, because the TD Economics forecast is already included in the Consensus Economics Inc.

231. Mr. Coyne formed his forecast by taking the average of the 3-month-out and 12-month-out forecasts of the respective 10-year government bond yields, as reported in October 2008 by Consensus Economics Inc. and adding the daily average of the previous month's historical spread between 10-year and 30-year bonds. Mr. Coyne thereby predicted a risk free rate of 4.13 percent for Canada and 4.44 percent for the U.S.[190]

232. Dr. Vilbert also adopted a forecast from Consensus Economics Inc., using their August 2008 forecast of 10-year Canadian government bond yields of 4.3 percent. To this forecast for 10-year bonds, Dr. Vilbert added an additional 20 basis points to adjust the forecast to the average maturity of the long-term bond yields used to estimate the long-term market risk premium, yielding a long term risk free interest rate forecast of 4.5 percent for Canada. Dr. Vilbert used this forecast of the Canadian long term risk free rate for both his Canadian and U.S. CAPM analyses.

233. The Commission recognizes that, at the time these forecasts were made, the volatility in capital markets made it difficult to establish a consistent forecast and forecasts from all sources varied depending on the day, week or month that the forecast was calculated. The Commission considers that, at the time of the Proceeding, forecasts of the risk-free rate in the range of 4.13 percent to 4.50 percent were reasonable for the Canadian market.

[186] Dr. Booth Revised Evidence, Exhibit 292.03, page 18.
[187] Exhibit 179.02, page 186.
[188] Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.3.
[189] Ibid.
[190] Exhibit 50.01, Section 3.0, Evidence of Mr. Coyne, page 27 lines 8-19.

5.2.2 Market Equity Risk Premium

234. The next element of the CAPM analysis is the market equity risk premium (MERP). Parties recommended different market equity risk premiums.

235. Dr. Booth estimated the market equity risk premium at 5 percent noting that "[t]his is significantly higher than the experienced market risk premium earned in Canada over almost any time period, but takes into account the unexpected performance of the bond market, due to declining long Canada bond yields, and the reduction in risk in the bond market compared to a few years ago."[191] Dr. Booth demonstrated, upon reviewing historical data, that conditions in the bond market prior to 1956 were substantially different from what they had been since. In his view, this was due to an increase in bond market returns, commensurate with an increased risk in investing in government bonds, arising from government deficits and inflation. Consequently, he said, much of the drop in the market risk equity premium since 1956 was caused by an increase in the risk of investing in long Canada bonds, not by a decline in equity returns. With a reduction in government deficits since the mid 1990s, the yields on government bonds have declined and, by comparison, the market risk equity premium has increased.[192]

236. Drs. Kryzanowski and Roberts employed four methods to estimate the market equity risk premium, relying primarily on the first and using the remaining methods to confirm the findings from the first. They based their initial analysis on a blended average of the arithmetic and geometric mean market equity risk premiums for the time period from 1952 to 2008 because "the exclusive use of the arithmetic mean MERP results in an overstatement of the prospective MERP, and that the exclusive use of the geometric mean MERP results in an understatement of the prospective MERP."[193] This analysis yielded a market equity risk premium of 4.20 percent. Drs. Kryzanowski and Roberts then conducted a survey of Canadian and U.S. market equity risk premium estimates as reported in recent studies published in refereed journals. From this survey, they concluded that a forward-looking market equity risk premium for Canada is not more than 5.10 percent.[194] Their third estimate was based on the DCF estimation method, again concluding that a forward-looking market equity risk premium for Canada is not more than 5.10 percent. Finally, Drs. Kryzanowski and Roberts undertook a survey of knowledgeable professionals to confirm their estimate of the market equity risk premium. They concluded, again, that a forward-looking market equity risk premium for Canada is not more than 5.10 percent. On the basis of their findings from these four analytical methods, and a number of other "balancing" considerations discussed in their evidence, and further providing for an allowance for estimation error, they forecast a market equity risk premium of 5.10 percent for an "average-risk" utility for 2009.[195]

237. Mr. Coyne estimated the market equity risk premium as the mid-point of the long horizon equity risk premium data averaged over the longest period for which data were available from Morningstar Ibbotson for both the U.S. and Canada. The analysis for the U.S. data from 1926 to 2007 yielded a 7.10 percent market equity risk premium. The results for Canada from 1936 to 2007 yielded a market equity risk premium of 5.40 percent; and from 1939 to 2007, the U.S. Ibbotson data yielded a 5.80 percent market equity risk premium. Based on this analysis,

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191 Dr. Booth Revised Evidence, Exhibit 292.03, page 82.
192 Dr. Booth Revised Evidence, Exhibit 292.03, page 81, line 18 to page 82, line 10.
193 Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.1.1.3.
194 Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.1.2.2.
195 Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.1.5.

Mr. Coyne selected 6.25 percent as his market equity risk premium, viewing the result as "an appropriate North American indicator."[196]

238. Dr. Vilbert argued that "it is likely that investors risk aversion increases during times of financial distress so that the MRP currently is higher than in the recent past."[197] He maintained his estimate from the previous National Energy Board proceeding (RH-1-2008), with support from "the latest academic evidence" including a recent paper on the worldwide premium,[198] and concluded that the market equity risk premium is 5.75 percent.

239. In the Commission's view, the 6.25 percent recommendation of Mr. Coyne is unreasonably high. Mr. Coyne estimated a "North American indicator" based on what appears to be an average of the U.S. and Canadian market equity risk premium figures from the Ibbotson data. The Commission does not agree that Mr. Coyne's "North American indicator" is sufficiently representative of the market equity risk premium in the Canadian investment market. The Commission also notes that Mr. Coyne's own analysis of the Canadian market equity risk premium, based on the Ibbotson data, yielded a market equity risk premium of 5.40 percent, which is similar to the findings of the other expert witnesses, which were in the range of 5.00 percent to 5.75 percent.

240. Accepting Dr. Vilbert's assertion that the market equity risk premium may currently be higher than in the past, a market equity risk premium of 5.75 may be warranted. Therefore, the Commission finds the range of 5.00 percent to 5.75 percent market equity risk premium to be reasonable.

5.2.3 Beta

241. The next element of the CAPM analysis is the beta. Beta is a statistical measure describing the relationship of a stock's return with that of the stock market as a whole. In the Commission's view, the proper beta to use is that which represents the relative risk of stand-alone Canadian utilities. This is the element of CAPM where the estimates of the expert witnesses diverged the most, providing a recommended range of 0.50 to 0.93.

242. Based on his analysis of the relative standard deviation of ROEs, recent standard beta estimates for utility holding companies, recent beta estimates for utility sub-indexes and a two-factor analysis of utility returns against the TSX composite return, Dr. Booth observed that there is no statistical evidence that the risk of Canadian utility holding companies for the last ten years has consistently been within the "normal" range of 0.40 to 0.60 experienced in the mid to late 1990s. He opined that this is because "normal market conditions are becoming unusual as capital markets seem to be jumping from one bubble to another."[199] He concluded, on the basis of judgment and a consideration that betas tend to revert to their long run average, that the beta range should be estimated at 0.45 to 0.55. For his CAPM analysis, Dr. Booth employed a beta estimate of 0.50, stating that he found "nothing in the recent risk measures to indicate that this risk ranking has changed in any substantial way."[200]

196 Exhibit 50.01, Section 3.0, Evidence of J. Coyne, page 29, line 31 to page 30, line 7.
197 Vilbert Evidence, Exhibit 58.02, page 24.
198 Ibid.
199 Dr. Booth Revised Evidence, Exhibit 292.03, pages 78-79.
200 Ibid. page 79.

243. Mr. Coyne used adjusted betas from Value Line and Bloomberg to develop his beta estimates. He argued for the use of adjusted betas on the grounds that "an individual company beta is more likely than not to move towards the market average of 1.00 over time" and "it is necessary to adjust forecasted betas toward 1.00 in an effort to improve forecasts."[201] [202]

244. Mr. Coyne calculated betas for four proxy groups, a U.S. Gas Distribution proxy group at 0.80, a U.S. Electric Distribution proxy group at 0.81, a Gas Pipeline group with a mix of Canadian and U.S. utilities at 0.90, and a Canadian proxy group at 0.72.[203]

245. Dr. Vilbert used three proxy groups to estimate betas, a Canadian utilities sample, a gas local distribution company sample with both Canadian and U.S. companies and a sample of Master Limited Partnership pipelines with both Canadian and U.S. companies. He calculated rolling beta estimates using monthly excess returns over the previous 60 months. Market returns were represented by either the S&P/TSX or the S&P 500 indices, as appropriate, and risk-free rates were taken as Canadian and U.S. 91-day T-bill returns, as appropriate, employing Value Line unadjusted betas for his Gas LDC and MLP pipeline samples and Bloomberg unadjusted betas for the Canadian sample.[204] For the reasons noted previously, the Commission did not consider Dr. Vilbert's analysis for MLP pipelines.

246. Dr. Vilbert modified his Canadian beta estimates by using adjusted betas, noting that the result of his initial analysis did not yield "an accurate measure of the relative risk of the sample companies in many of the periods."[205] He argued for adjusted betas because he considered his Canadian sample to be sensitive to interest rate changes and noting that "the 60-month betas for the Canadian Utilities sample are still increasing from their lows of the "tech bubble" period."[206] On the basis of this analysis including the adjustments, Dr. Vilbert recommended a beta for Canadian utilities of 0.63 but qualified his estimate as downward biased because "the period of turmoil in the market that resulted in low or negative beta estimates is still included in the estimation period."[207]

247. Drs. Kryzanowski and Roberts based their beta estimate on an analysis of 60 months of return data on actual market transactions for a sample of ten Canadian publicly traded utility holding companies.[208] Drs. Kryzanowski and Roberts calculated the average betas of 0.315 for the period 1992 to 2008, and 0.583 for 1990 to 1994. The means of the mean cross-sectional betas for the first five, middle five, and the last (most recent) five rolling five-year periods were 0.539, 0.150 and 0.255, respectively. They stated that there is no evidence that the normal tendency of this sample of utility betas is to revert back to a market beta of one and therefore, there is no justification for using non-standard (adjusted or inflated) betas.[209] On the basis of

[201] Exhibit 50.01, Section 3.0, Coyne Evidence, page 28.
[202] Mr. Coyne referenced studies by Blume to support his use of adjusted betas, the same references cited by Drs. Kryzanowski and Roberts in their explanation of the rationale for using adjusted betas.
[203] Exhibit 50.01, Section 3.0, Coyne Evidence, page 15.
[204] Vilbert Evidence, Exhibit 52.02, page 50.
[205] Ibid. page 51.
[206] Ibid. page 55.
[207] Ibid. page 56.
[208] Exhibit 179.04, Evidence of Drs. Kryzanowski and Roberts, Schedule 3.13.
[209] Exhibit 179.02, Drs. Kryzanowski and Roberts, pages 178-180.

their analysis, they concluded that the rationales supporting the use of non-standard betas, as advocated by Mr. Coyne, are incorrect in a Canadian context.[210]

248. Drs. Kryzanowski and Roberts also found that the average correlation between utilities in their sample and the S&P/TSX Composite has declined substantially from the most distant five-year period to the more recent five-year period (0.495 versus 0.247), and is quite low at 0.263 when averaged over 15 rolling five-year periods. They concluded from this finding that "an average utility is now more desirable as an investment because of its enhanced potential for portfolio risk reduction. A greater potential for risk reduction leads to a reduction in an asset's own equity risk premium all else held equal. This reduction in the correlations between the returns of the utilities and the market also contributes to the reduction in the betas of the sample of utilities."[211] They also noted that "the adoption of adjustment mechanisms to automatically adjust ROE on a generic basis by various Canadian regulatory bodies has most likely contributed to this reduction in risk."[212]

249. In addition, Drs. Kryzanowski and Roberts calculated the standard deviation of returns for their sample of utility holding companies and Dr. Vilbert's sample, over rolling five-year periods. They concluded that there is no evidence that the total investment risks of their sample of Canadian utility holding companies or Dr. Vilbert's sample of five Canadian utility holding companies have increased since the last generic proceeding.[213] They recommended, on the basis of their several analyses, that a beta of 0.52 is appropriate and that this estimate is conservatively high, and provides sufficient coverage for any estimation errors.[214]

250. Finally, Dr. Vander Weide recommended a beta for utilities of 0.93, based on data from the U.S.,[215] but he did not provide an overall CAPM estimate.

251. The Commission is persuaded by the empirical analysis of Drs. Kryzanowski and Roberts that there is insufficient evidence to support the use of adjusted betas for Canadian utilities if the purpose of the adjustment is to adjust the beta towards one and therefore, beta should not be adjusted towards one. Therefore, the Commission rejects Mr. Coyne's beta results as unreasonably high, because he adjusted his beta estimates on the assumption that they would revert to 1.00. In other words, his analysis assumes that, in time, utilities would be as risky as the market as a whole.

252. Likewise, the Commission rejects Dr. Vander Weide's recommendation of 0.93 as unreasonably high, noting that it is based strictly on U.S. data. In this regard, the Commission is also mindful of Dr. Vilbert's assertion during cross examination when commenting on Dr. Vander Weide's beta estimate, that he had never encountered a Canadian utility beta that high.

> As I say, I can't get my betas to get anywhere near that high when I estimate them, not that I'm trying to make them high but they don't come out that high. And my sense is that

[210] Ibid. page 185.
[211] Ibid. page 181.
[212] Ibid.
[213] Ibid. page 182.
[214] Ibid. page 185
[215] Dr. Vander Weide Rebuttal Evidence, Exhibit 282.01, page 25 and Transcript, pages 2173 to 2174.

> regulated utilities are generally not quite that risky relative to the market, that a .65 is a relatively reasonable market estimate of what the beta should be.[216]

253. The Commission understands that estimating a beta for Canadian stand-alone utilities is difficult. The experts in this proceeding have employed a variety of techniques, data sets and considerable professional judgment in their beta proposals. Dr. Vilbert's comments with respect to the challenges of calculating a beta for Canadian utilities speaks to this challenge.

> ... the concern I do have is that it's been consistently difficult over the last ten years or so that I've been working in Canada to estimate the betas for your utility companies … I bet you I've tried a dozen different ways to estimate the betas and I will tell you that from proceeding to proceeding, the method I think I've finally figured out how to capture the essence of the risk of these companies as likely as not doesn't work the next time.[217]

254. In the Commission's judgment, Dr. Booth's recommended beta of 0.50 represents a reasonable lower bound for beta for stand-alone Canadian utilities. The Commission recognizes that Dr. Vilbert's analysis was intended to modify his unadjusted Canadian sample results to account for his judgment that the unadjusted results were not adequately representative of forward looking expectations, which is consistent with Dr. Booth's rationale for adjusting his beta recommendation. The Commission finds Dr. Vilbert's Canadian beta estimate of 0.63 to be a reasonable upper bound for beta for stand-alone Canadian utilities. The Commission notes that the beta recommendation of Drs. Kryzanowski and Roberts falls within the range of 0.50 to 0.63 discussed above.

5.2.4 Flotation Allowance

255. The parties all agreed that a flotation allowance is normally included in the CAPM model to account for the administrative costs and issuance costs for the investment banker, any impact of under-pricing a new issue, and the potential for dilution. The CAPM calculations presented in the Proceeding and included in the Commission's Table 7 above include the usual regulatory convention of adding 0.50 percent to the CAPM estimate. The Commission agrees that a flotation allowance of 0.50 percent is warranted.

5.2.5 The Commission's Resulting CAPM Estimate

256. Applying its findings on the individual components of CAPM, the Commission calculates a range of CAPM ROE results for stand-alone Canadian utilities of 6.63 percent to 8.12 percent, without the flotation allowance. With a flotation allowance the Commission calculates a CAPM ROE range of 7.13 percent to 8.52 percent.

5.3 Discounted Cash Flow Model

257. The Discounted Cash Flow Model is used to estimate the cost of a company's common equity based on the expected dividend yield of the company's shares plus the expected future dividend growth rates. The DCF method calculates ROE as the rate of return that equates the estimated future stream of dividends with the current share price.

216 Transcript, page 2424.
217 Transcript, page 2422.

258. Mr. Coyne states in his evidence:

> The DCF model evolves from the basic premise that investors will value a given investment according to the present value of its expected returns over time. This model is widely used in valuing entire companies by discounting the projected cash flows for the enterprise. When valuing the entire enterprise, financial analysts discount the future stream of free cash flows. When considering the common stock of a company, investors consider the future stream of dividends as cash flow from this investment (characterized as the Dividend Discount Model).[218]

259. Evidence to support proposed ROEs based on an application of the DCF model was provided by Mr. Coyne, Dr. Vilbert and Dr. Vander Weide.

260. The following table sets out the individual DCF components and resulting ROE levels for each of the parties that presented evidence on the DCF model. The Commission notes that, with the exception of Mr. Coyne, the experts did not include a 0.50 percent increment for flotation costs in their DCF analyses. The Commission considers that the DCF results should be adjusted to include flotation costs. As with the CAPM analysis, the Commission adjusts the DCF results to include a 0.50 percent flotation allowance.

Table 8. Summary of DCF Estimates

Expert Witness	Dividend Yield	Stage 1 Growth Rate	Stage 2 (if applicable) Growth Rate	Indicated ROE (%)	Flotation Allowance (%)	ROE (%)
Dr. Vander Weide 30 U.S. Electric Companies	See Exhibit 8	See Exhibit 8	n.a.	11.8	0.50	12.3
Dr. Vander Weide 11 U.S. Natural Gas Companies	See Exhibit 9	See Exhibit 9	n.a.	10.8	0.50	11.3
Mr. Coyne[219] 6 U.S. Gas LDCs	4.24%	5.5%	n.a.	9.74	0.50	10.24
Mr. Coyne 6 U.S. Electric Dist.	4.82%	4.88%	n.a.	9.70	0.50	10.20
Mr. Coyne 5 North America Gas Transmission	3.12%	8.11%	n.a.	11.23	0.50	11.73
Mr. Coyne 5 Canadian Utilities	3.87%	6.41%	n.a.	10.29	0.50	10.79
Mr. Coyne Average				10.24	0.50	10.74
Dr. Vilbert 5[220] Canadian Utilities[221] - single-stage	3.42%	6.24%	n.a.	10.04	0.50	10.54
Dr. Vilbert 5 Canadian Utilities[222] -multi-stage	3.42%	See Schedule[223]	4.1%	8.38	0.50	8.88

[218] Exhibit 50.01, Section 3.0, Evidence of J. Coyne, page 16, lines 9-15 .
[219] Exhibit 50.01 ATCO, Coyne Evidence Schedule JMC-04, PDF pages 193-196 of 393.
[220] Exhibit 52.02, Table MJV-6, Canadian Utilities, Emera, Enbridge, Fortis Inc., and TransCanada Corp.
[221] Exhibit 52.02, Table MJV-6 panel A, and MJV-7 panel A.
[222] Exhibit 52.02, Table MJV-6 panel B, and MJV-7 panel B.
[223] This refers to Dr. Vilbert's Schedules in Exhibit 52.02.

Expert Witness	Dividend Yield	Stage 1 Growth Rate	Stage 2 (if applicable) Growth Rate	Indicated ROE (%)	Flotation Allowance (%)	ROE (%)
Dr. Vilbert 11 U.S. Gas LDCs - single-stage	See Schedule	See Schedule	n.a.	8.8	0.50	9.3
Dr. Vilbert 11 U.S. Gas LDCs - multi-stage	See Schedule	See Schedule	4.8%	8.8	0.50	9.3
Dr. Vilbert Subset of the 11 U.S. Gas LDCs - single-stage	See Schedule	See Schedule	n.a.	8.3	0.50	8.8
Dr. Vilbert Subset of the 11 U.S. Gas LDCs[224] - multi-stage	See Schedule	See Schedule	4.8%	8.5	0.50	9.0

261. Mr. Coyne applied the DCF model to the same set of proxy groups he used in his CAPM analysis. He calculated the current dividend yield for each company in each proxy group by dividing the annualized current dividend by the 90-day average stock price. Mr. Coyne argued that the 90-day average period was long enough to eliminate short-term trading volatility but still short enough to reflect recent value. This calculated dividend yield was increased by one-half of the assumed growth rate to reflect the expected growth in dividends over the coming year.[225] To these dividend yields, he applied a growth rate forecast based on forward-looking growth estimates from Value Line, Zacks Investment Research, Thomson First Call and Bloomberg for each of the proxy companies,[226] in some cases averaging the estimates where they were not available for specific companies, and adjusting for any outliers in the data.

262. To calculate his final DCF results, Mr. Coyne added the expected dividend yield to the average growth rate. He calculated a low DCF result by taking the lowest of the available growth rates for a given company plus the expected dividend yield for that anticipated level of growth and the high DCF result in the same manner. He then averaged the low, mean and high company-specific DCF results to obtain “unadjusted DCF results” for each proxy group. Finally, Mr. Coyne added a 50 basis point allowance for flotation, as he had with the CAPM model.

263. Mr. Coyne’s DCF analysis yielded the following ROEs for each of his proxy groups.[227]

Table 9. Summary of Mr. Coyne’s DCF Analysis

Proxy Group	Low (%)	Mean (%)	High (%)
U.S. Natural Gas Distribution Utilities	8.82	10.24	11.77
U.S. Electric Distribution Utilities	9.78	10.20	10.60
Gas Transmission Pipelines	10.14	11.73	13.38
Canadian Utilities	10.02	10.79	11.69
Average	9.69	10.74	11.77

224 Exhibit 52.02, Tables MJV-17 and 18.
225 Exhibit 50.01, Section 3.0, Coyne Evidence, page 98.
226 Ibid. page 99.
227 Exhibit 50.01, Section 3.0, Evidence of J. Coyne. page 26, line 22.

264. Mr. Coyne employed the results of his DCF analysis and his CAPM analysis to determine “the relative ranges of ROE for each sector.” His remaining analyses were intended to corroborate his findings from these two methods.[228]

265. Dr. Vander Weide applied the DCF model to two proxy groups of Value Line U.S. gas and electric utilities. To establish his proxy groups, Dr. Vander Weide selected companies that paid dividends during every quarter and did not decrease dividends during any quarter of the previous two years; had at least three analysts included in the Institutional Investors Estimation Service mean growth forecasts; were not in the process of being acquired; had a Value Line Safety Rank of 1, 2, or 3; and had investment grade S&P bond ratings.

266. Dr. Vander Weide’s DCF analysis for his proxy group of U.S. natural gas companies produced an ROE of 10.8 percent. His analysis for his proxy group of U.S. electric companies produced an ROE of 11.8 percent. Dr. Vander Weide calculated that the average DCF result for his comparable groups was 11.3 percent, and he concluded that the ROE for his comparable companies was 11.3 percent, before flotation.

267. Dr. Vilbert included multi-stage forms of the DCF model which allowed for varying dividend growth rates in the near term before assuming a perpetual growth rate, beginning in year eleven. He used the applicable forecast growth of GDP for his Canadian and U.S. analysis respectively as the long-term growth rate beyond year eleven.[229] Dr. Vilbert applied his DCF analysis to the same sample of proxy companies that he used for his CAPM analysis. His analysis, using his multi-stage approach to calculating the expected dividend growth rate, produced ROEs of between 9.0 percent and 9.3 percent for his U.S. proxy groups and 8.88 percent for his set of Canadian proxy companies, after flotation.

268. Drs. Kryzanowski and Roberts argued that implementing the DCF method at the individual utility level, as the utility experts had done, is fraught with implementation biases.[230] Among these alleged biases are problems with using analysts’ “bottom-up” growth rate forecasts that may be optimistic. Dr. Booth also spoke to similar problems with estimating growth rates in DCF analyses, arguing that “it is generally accepted that analysts’ earnings forecasts are biased high.”[231] On the contrary, however, Mr. Coyne argued that “[w]hether growth rates are higher or lower than what is actually achieved is irrelevant to what we are measuring – investor expectations and the influence of those expectations on required returns.”[232]

269. The Commission is concerned that many of the proxy companies used by the experts in their DCF analyses are holding companies that are engaged in significant unregulated activities and is also concerned with the potential upward bias in analysts’ growth estimates. Nonetheless, the Commission considers that a multi-stage DCF analysis that adjusts the long run growth expectations to a reasonable level can provide some guidance to the Commission. The Commission will, therefore, consider the results of some of Dr. Vilbert’s multi-stage DCF analyses in its deliberations, as further explained below.

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[228] Ibid. page 13.
[229] Dr. Vilbert Evidence, Exhibit 52.02, page 37.
[230] Drs. Kryzanowski and Roberts, Exhibit 179.02, page 263.
[231] Dr. Booth Revised Evidence, Exhibit 292.03, Page 104
[232] Exhibit 50.01, Section 3.0, Evidence of Mr. Coyne, page 30.

270. With respect to the analyses of Dr. Vander Weide and Mr. Coyne, the Commission considers that DCF growth estimates that exceed the expected growth in GDP over the long run are unrealistic, particularly for a stand-alone regulated utility. Dr. Vander Weide's DCF estimates assumed dividend growth rates that frequently exceeded the expected Canadian GDP nominal growth rate of 5 percent to 6 percent, including inflation.[233] Mr. Coyne's DCF analyses similarly forecast dividend growth rates that are, for all but one of his proxy groups, above the expected GDP nominal growth rate. For this reason, the Commission rejects the results of the DCF analyses of both Dr. Vander Weide and Mr. Coyne.

271. Dr. Vilbert provided DCF results for both a sample of Canadian utilities and a sample of U.S. gas utilities. He provided single-stage and multi-stage growth estimates in his DCF analyses. The Commission considers his multi-stage growth estimates, which employed a growth assumption of 4.1 percent beyond 11 years, to be informative. Dr. Vilbert's Canadian sample multi-stage DCF rate of return estimate was 8.38 percent before flotation. Dr. Vilbert's multi-stage DCF estimate, based on 11 U.S. gas utilities, was 8.8 percent before flotation.

272. In Dr. Vilbert's Canadian proxy sample, the unadjusted DCF results for Emera Inc., with holdings consisting of mostly regulated utilities, was 8.8 percent including a 0.50 percent flotation adjustment. Dr. Vilbert's unadjusted DCF result for Fortis Inc., with holdings that are largely Canadian regulated utilities, was 9.2 percent including a 0.50 percent flotation adjustment. Notwithstanding the concerns raised by Drs. Kryzanowski and Roberts with respect to the application of the DCF method to individual companies, the Commission is prepared to take into account the returns expected for these companies in its assessment of a fair return for Alberta utilities. In addition, the Commission recognizes that, in Dr. Vilbert's DCF analyses of both U.S. and Canadian utilities employing a multi-stage growth estimate, the calculated ROE is in the range of 8.9 percent to 9.3 percent, including 0.50 percent flotation.

273. Overall the Commission finds that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 percent to 9.3 percent, assuming that the equity ratio has been set to target a credit rating in the A range.

5.4 Comparable Earnings

274. The comparable earnings test examines the accounting returns of a company as a percentage of its book value. The ATCO expert witnesses provided comparable earnings for a proxy group of companies that, in their view, were comparable to Alberta stand-alone utilities. Comparable earnings evidence provided by Mr. Coyne and Ms. McShane showed a range of comparable earnings from 11.2 percent to 13.6 percent.

275. Dr. Booth included, in his evidence, Statistics Canada's estimated average accounting earnings for Corporate Canada, for the period from 1998 to 2007. This data showed an average accounting return of 9.1 percent for the period.

[233] Exhibit 179.04, Schedule 3.8, Panel A.

276. The comparable earnings results are set out in Table 10, below.

Table 10. Summary of Comparable Earnings Results

Expert Witness	Method	Sample Description	Comparable or Reference ROE
Mr. Coyne[234]	Achieved recent ROE on Canadian low risk industrials	14 low risk companies all of which were in Consumer Products or Media segment	13.6%
Dr. Booth	Past ROE on overall Equity Market	Statistics Canada ROE for Corporate Canada	9.1%[235]
Ms. McShane[236]	Achieved ROEs of U.S. Electric Utilities	29 U.S. Electric Utilities Rated A- or higher 49% average equity ratio	12.4% average 11.6% median 2005-2007
Ms. McShane[237]	Achieved ROEs of U.S. Gas Utilities	14 U.S. Natural Gas Utilities Rated A- or higher 48% average equity ratio	12.1% average 11.2% median 2005-2007

277. Mr. Coyne measured returns in relation to book value for a proxy group of assumed low risk industrial companies headquartered in Canada. Mr. Coyne used Globe Investor to compile a list of all publicly-traded media, consumer products, and utility holding companies in Canada. He considered these sectors "to represent industrial consumer staples with relatively stable demand and significant capitalization."[238] He obtained quarterly earnings per share data and quarterly return on common equity data for the trailing 12 months going back 5 years for all companies, and then selected only the companies with steady positive annual EPS and ROE for all years; and eliminated companies with a coefficient of variation for earnings per share of greater than 50 percent. This was intended to mimic the stable earnings of the utilities. He reported results that both included and excluded utility companies, recognizing the circularity arising from results that include utilities. The Commission included in the table above his sample that excluded utilities to avoid circularity.

278. Ms. McShane's ROE estimates were developed from two separate samples: all U.S natural gas utilities rated A- or higher and all U.S. electric utilities rated A- or higher. Ms. McShane's results for natural gas utilities were on average 12.1 percent. Her results for electric utilities were on average 12.4 percent. ATCO submitted that the evidence of Ms. McShane[239] demonstrated that A- rated U.S. utilities on average have achieved earnings higher than have been allowed by regulators in Canada and, to a greater extent, higher than the earnings of the ATCO Utilities.[240]

234 Exhibit 50.01, Section 3.0, Coyne Evidence, page 34 and Schedule JMC-07.
235 Booth Revised Evidence, Exhibit 292.03, page 28.
236 Exhibit 50.01, Section 4.0, McShane Evidence, Schedule 4.
237 Exhibit 50.01, Section 4.0, McShane Evidence, Schedule 5.
238 Exhibit 50.01, Section 3.0, Coyne Evidence. page 34.
239 Exhibit 279.01, McShane Rebuttal at pages 14-15.
240 ATCO Argument, Exhibit 390.02, page 92.

279. Drs. Kryzanowski and Roberts did not provide a comparable earnings test because they state that "it is of dubious scientific merit …and thus unsuitable for use in determining a fair ROE for a utility." They argued that there is neither any theoretical underpinning nor any empirical support for the comparable earnings method for estimating a regulated fair rate of return for a utility. In their view, "as an accounting-based measure, comparable earnings will only coincide with the investor's opportunity cost (required rate of return) by accident. There is no conceptual reason to expect that comparable earnings represent a rational expectation of an investor's desired rate of return from investing in the firm."[241]

280. In Decision 2004-052, the Board rejected the comparable earnings test results as a measure of return on a comparable investment.

> The CE [comparable earnings] test measures **actual** earnings on **actual book value** of comparable companies, which in the Board's view does not measure the return "*it **would** receive if it **were** investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise*" (emphasis added) (unless the securities were currently trading at book value).[242]

281. The Commission agrees with the Board that the comparable earnings test examines accounting earnings on book value for companies, but not returns actually available to, or required by investors in the market. In the Commission's view, because the comparable earnings test does not deal with returns available to investors in capital markets, it is not consistent with the comparable investment standard and is not a test upon which any weight should be placed. Consequently, the Commission will not consider the comparable earnings evidence.

5.5 Returns Awarded by Other Regulators

282. With respect to awarded returns for other Canadian utilities, a number of the utilities[243] argued that taking into consideration awards from regulators employing an adjustment mechanism similar to that used by the Commission would be circular. Accordingly, they recommended that the Commission place no weight on these awards. Mr. Coyne stated that:

> In Canada, the majority of utilities are bound by the same ROE formula, as are the utilities in Alberta, which is linked to the change in government bond yields. To evaluate the fairness of those ROE awards by looking to other Canadian utilities is analogous to looking in the mirror to compare your appearance to the reflection's. The potential for circularity of such a benchmarking analysis renders it, for the most part, meaningless as an independent source of comparability.[244]

283. CAPP took the position that awards by other regulators, in both Canada and the U.S., should not be considered:

> … reference to either sets of decisions – Canadian and U.S. – as benchmarks of what is a fair return is unnecessary since the better approach is to examine the evidence of required returns estimated by experts using techniques founded on sound principles of finance.[245]

[241] Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 324.
[242] Decision 2004-052, page 23.
[243] AltaLink, EPCOR utilities, FortisAlberta and ATCO utilities.
[244] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3.0, page 41.
[245] Written Argument of CAPP, Exhibit 388.02, paragraph 403.

284. The Commission agrees with CAPP that the better approach is to examine the direct evidence of the experts in this proceeding, particularly because the awards of other regulators were established on the basis of a different record.

285. In Section 3.2.3 of this Decision, the Commission determined that it would not consider return awards by U.S. regulators, although it expected market determined returns for U.S. utilities may be examined on a market risk-adjusted basis in assessing a fair return for stand-alone Alberta utilities.

286. The Utilities generally recommended that the Commission give careful consideration to the NEB's recent TQM Decision, which set an allowed return for 2007 and 2008. As noted in Section 3.3 of this Decision, the Commission has distinguished the TQM Decision and indicated it would not consider that decision in determining a fair return for Alberta utilities.

287. The Commission observes that the determination to place no weight on Canadian allowed returns was also made by the NEB in the TQM Decision.

> On the question of whether litigated Canadian utility returns are similar because of problems of circularity, or whether they provide a valid signal because they represent independent conclusions reached on similar questions, the Board finds that there was no evidence that conclusively supported either view. Faced with contrasting opinions on the matter, and with the option of relying on returns from other submitted comparables, the Board placed no weight on Canadian litigated returns.[246]

5.6 Price-to-Book Ratios

288. An equity price-to-book ratio is calculated by dividing the current market price of a stock by its current book value per share. It is often used to compare a stock's market value to its book value. There was considerable debate during the proceeding as to the relevance, if any, of price-to-book ratios.

289. Calgary stated "as Dr. Booth noted … a price to book ratio does not indicate that precise level of the required fair return; rather it is indicative of the general level of the return. If the price to book ratio is below 1 then generally one would consider that the return is too low, while if it is above 1.2 it would generally indicate an adequacy to somewhat above that required or the fair return."[247] Dr. Booth also noted that the price-to-book data in the proceeding generally did not relate to stand-alone utilities and was therefore of little value.[248] Dr. Booth provided his calculations of the implied price-to-book ratios for a number of recent corporate purchases of utilities, which ranged from 1.31 to 1.80.[249]

290. Mr. Engen quoted from the text on *Public Utility Regulation* by Dr. James C Bonbright as follows:

> It follows that the common stocks of public companies which actually succeed in earning a fair rate of return as derived by a cost of capital technique can be expected to command

[246] TQM Decision, page 69.
[247] Calgary Argument, Exhibit 386.02, page 18.
[248] Transcript, pages 3544-3547.
[249] Dr. Booth Revised Evidence, Exhibit 292.03, pages 119-120.

substantial premiums over their book values or rate base values except in periods of a seriously depressed stock market.[250]

291. Mr. Engen provided a table which summarized his estimate of recent price-to-book values for a number of Canadian utility holding companies, which ranged from 0.6 to 1.7.[251]

292. Dr. Vander Weide questioned the relevance of the price-to-book ratios and submitted that:

> According to the DCF model, a company's stock price is equal to the present value of the company's expected future dividends, which, in turn, depend on its expected future ROEs. Thus, market-to-book ratios greater than 1.0, at best, imply that investors expect the company to earn more than its cost of equity at some time in the future. There is nothing in the DCF model that allows the analyst to draw inferences about the relationship between a company's historical ROE and its cost of equity from evidence on market-to-book ratios."[252]

293. Mr. Edmondson, appearing for ATCO, stated that when a company is valuing investment opportunities, price-to-book ratios would be one of the last tools it would employ.[253] With respect to corporate disposition and acquisition values, ATCO submitted that "while corporate acquisition transactions provide an indication of price-to-book ratios that investors have been willing to pay for utility assets, that information does not tell us whether investors consider the current return on regulated assets fair".[254]

294. Mr. Coyne submitted that a price paid to acquire a utility above book value may reflect some premium based on the acquiring company's belief that the acquisition will result in improved cost efficiency, or that the acquisition will provide them with an opportunity to serve an expanding territory or customer base, or that the acquisition provides a good strategic fit with other businesses in their corporate portfolio.[255] Both Mr. Coyne and Dr. Vander Weide indicated that in periods of inflation historical costs would be less than the current market cost and could account for price-to-book differences.[256]

295. The Commission considers that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios for utility holding companies.

296. AltaGas indicated that AltaGas Utilities Group Inc. trades significantly below its book value,[257] which discourages new investment as any dollar invested is worth less than a dollar to market investors[258] and is dilutive to existing shareholders.[259] However, the Commission notes

[250] Exhibit 52.02, Evidence of Aaron M. Engen, page 111 of 120.
[251] Exhibit 279.01, Rebuttal Evidence of Aaron Engen, pages 21-22.
[252] Exhibit 282.01, Vander Weide Rebuttal Evidence, page 10.
[253] Transcript, pages 1328-1329.
[254] Exhibit 128.02, AUC-ATCO UTL-6(b).
[255] Exhibit 128.02, AUC-ATCO UTL-15(d).
[256] Exhibit 128.02, AUC-ATCO UTL-15(b)b; Exhibit 282.01, Vander Weide Rebuttal Evidence, Exhibit 282.01, page 75.
[257] Exhibit 58.02, Tab 2, Vilbert Evidence, pages 16-17 and 22.
[258] Ibid.

that AltaGas Utilities Group Inc.'s financial statements dated December 31, 2007[260] indicate that AltaGas Utilities Group Inc. had substantial goodwill on its balance sheet. Because AltaGas is regulated on the basis of a return on rate base, which excludes goodwill, the price-to-book value of AltaGas Utilities Group Inc. is not of assistance.

297. The (equity) price-to-book ratio for the 2007 Fortis acquisition of Teresen Inc. was discussed on the record of the proceeding as a potential indicator of the price-to-book ratio for a stand-alone utility. However, there was considerable disagreement as to the correct calculation of the price-to-book value for this transaction. Price-to-book values in the range of 1.27[261] to 3.99[262] were provided. Despite the lack of agreement with respect to the exact calculation, the evidence is that the price paid for Teresen Inc. was at a price-to-book ratio above 1.2. It appears therefore that the awarded return for Teresen was at least fair, at the time of the transaction. However, there is ample evidence on the record that conditions in the market have changed significantly since the Teresen transaction in 2007, and the Commission cannot rely on this transaction as indicative of a fair return for 2009.

5.7 Returns Available on High Grade Corporate Bonds

298. Returns available on Canadian corporate bonds with investment grade ratings of BBB or higher were continuously changing over the course of this proceeding. The spread between the yield on high grade corporate bonds over the risk free rate spiked upward during the last quarter of 2008 and the first quarter of 2009. Mr. Engen for the ATCO Utilities referred to the historical A- corporate bond spread and the effects of the financial crisis on that historical spread as at the end of March 2009 as follows:

> The current credit spread for Canadian A-rated corporate bonds is 308 basis points (for the two quarters ending March 2009), whereas historically that average spread was approximately 125 basis points.[263]

299. CAPP acknowledged that high grade Canadian corporate bond spreads had indeed widened during the financial crises but observed that spreads were trending downwards as at the close of the oral hearing:

> Corporate bond spreads have come down significantly since the dark days when CAPP's evidence was prepared. Generic corporate bond spreads had come down to about 200 basis points in early June with utility bond spreads at 170, 175 basis points. CU Inc.'s spreads as of early June were down to 168 basis points. … The effect of the financial crisis is temporary and the evidence of the ability to attract capital during the crisis demonstrates that regulatory support is sufficient.[264]

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[259] Exhibits 157.01, AUC-AUI-10(a) and 163.01, UCA-AUI-12(a). The UCA argued that the ratio is only below one if goodwill and other intangibles are included in its book value. UCA Reply Argument, page 12

[260] Exhibit 58.02, AltaGas Evidence, Section 1.9.4, page 1.

[261] Transcript, page 1319, line 17.

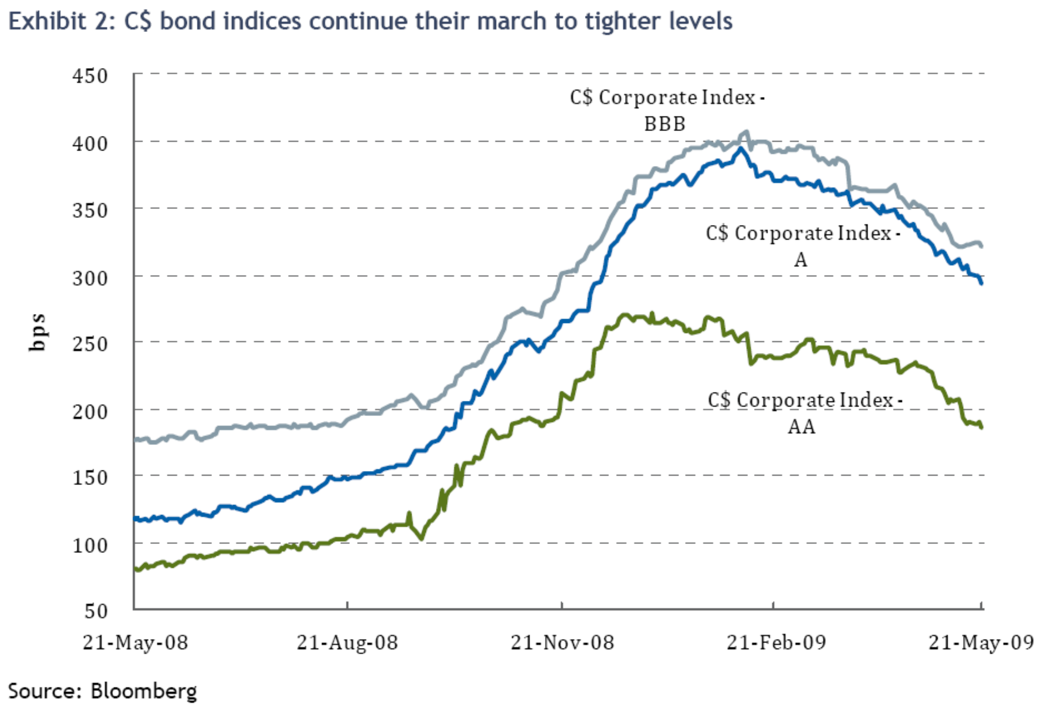
[262] Exhibit 117.03, UCA-EPC, page 120, lines 10-11.

[263] Coyne Rebuttal Evidence, Exhibit 279.01, page 3.

[264] CAPP Written Argument, Exhibit 388.02, pages 6-7.

300. Figure 1 below was provided in an undertaking response by Dr. Roberts. It demonstrated that the high grade corporate bond credit spreads have recovered significantly since the peak of the financial crisis:[265]

Figure 1 Canadian Bond Spreads

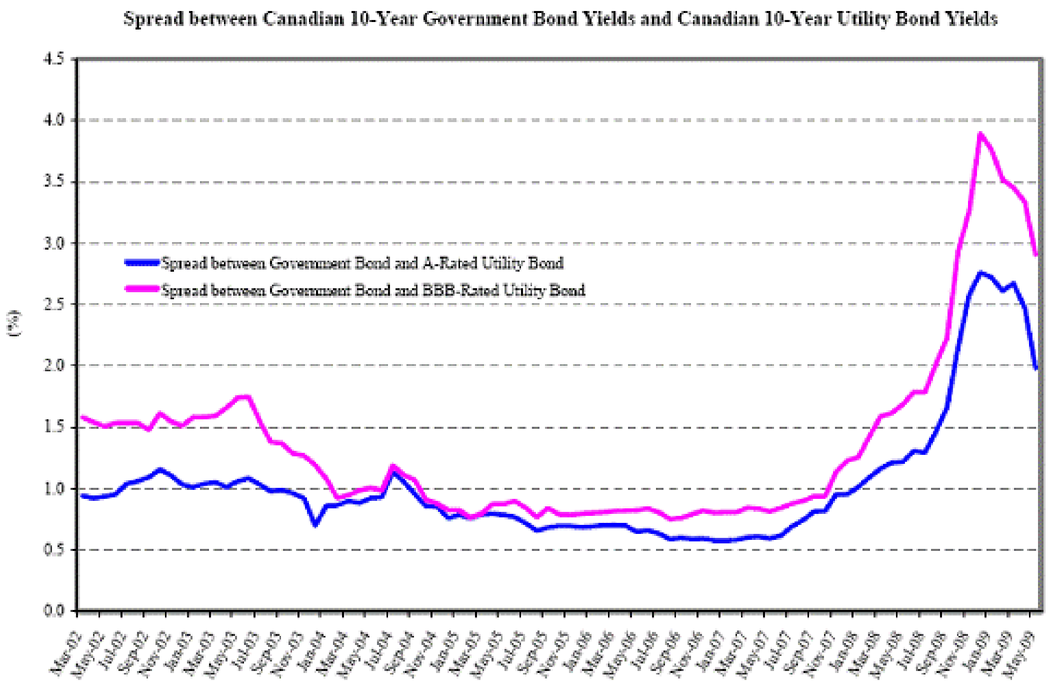


301. Canadian utility bonds are a subset of Canadian high grade corporate bonds. As demonstrated in Figure 2 below the experience of Canadian utility bonds has been similar to Canadian corporate bonds in general with spreads to long Canada bonds widening in the spring of 2008 and starting to decline in the later half of 2008. Figure 2 below was provided by Dr. Vilbert in an undertaking response by Dr. Vilbert to counsel for the UCA:[266]

[265] Undertaking given at Transcript, page 3018, line 1 to provide most recent RBC Capital Markets Credit Weekly Report. Chart appears in Exhibit 368.04, the RBC Credit Weekly Report Volume 20 (May 22, 2009) at page 3.

[266] Undertaking given at Transcript Volume 14, page 13, Chart appears in Exhibit 359.01.

Figure 2 Canadian Utility Bond Spreads



Source: Bloomberg as of May 29, 2009.

Figure 2

302. Mr. Engen, on behalf of the ATCO Utilities, responded to a questions about recent decline in corporate bond spreads as follows:

> There's no question that spreads have tightened in, and for some issuers, materially, since the beginning of the year. Whether they go back to more normal spreads, difficult to say. Partly because I'm not sure what we mean when we say "normal spreads." There's no expectation, and that doesn't mean it won't happen, but there is no expectation amongst the various debt capital market groups, the investment banks, that we're going to go back to the spreads we saw last spring, last summer, where they were very, very tight. There was abundant capital. At the time, it appeared that investors either mispriced risk, didn't care about risk, or misunderstood the risks they were assuming.
>
> Our expectation is that we are seeing a repricing of risk. There may be some more tightening in, but we don't expect to see it going back to the ten-year average spreads that we saw, which for 30-year bonds stood around 100 basis points for A minus rated entities last spring, early summer.[267]

303. The utilities asserted that a re-pricing of risk on high grade Canadian corporate bonds as demonstrated by the increased spreads must mean that there has been at least a similar increase in the cost of equity capital given that future return expectations of equity investors must always be higher than the lower risk expectations of debt investors. Dr. Booth appearing on behalf of CAPP appeared to accept the premise in the following exchange with Commission Counsel:

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[267] Transcript, page 1048, line 13 to page 1049, line 8.

> Q. So, sir, if I understand your position correctly, the utility equity issuer must be competing for the expected return on utility bonds, and that's what they are competing against, not the yield on bonds?
> A. DR. BOOTH: That's absolutely correct.[268]

304. Dr. Booth asserted however that it was not possible to draw direct linkages between increased credit spreads in the Canadian bond market and increase return expectations by equity investors. In his opening statement at the oral hearing Dr. Booth stated:

> However, as I say in my testimony, it is a fundamental error to assume that you can simply compare promised yields on default risky bonds with expected returns on stocks as if they are the same; they are not. Default spreads on A bonds are driven by different factors to those that drive equity risk premia.[269]

305. Dr. Booth stated in his evidence that trading liquidity less than that of Government of Canada bonds cause Canadian corporate bond spreads to suffer from a liquidity premium. Corporate bond spreads are wider partially because there is less trading liquidity in corporate bonds which is exacerbated by the many various tranches of corporate debt resulting in further liquidity premiums.[270] He further stated:

> It is quite obvious that unlike the fixed income market where there have been and always are serious liquidity problems during a recession and consequent flight to quality, no such liquidity problems are apparent in the equity market. Rewarding equity holders with a higher ROE as a result of liquidity problems in the bond market does not have any economic justification.[271]

306. Mr. Engen disagreed with Dr. Booth’s contention that higher bond spreads in Canada were a result of a liquidity problem brought on by the financial crisis and that it was improper to make assumptions about increased equity investor expectations from increased expectations of bond holders. In his Rebuttal Evidence Mr. Engen stated:

> …arguments suggesting that trading illiquidity is the driver behind the higher yield spreads for the Canadian generic A-rated corporate and utility spreads point to a fundamental misunderstanding of the bond market and how bonds are priced.[272]

307. Mr. Engen explained that corporate bonds do not need to be as frequently traded as Government of Canada bonds to avoid a liquidity premium. As an investment banker, Mr. Engen stressed that the Commission should have regard to actual capital market expectations by stating:

> …BMO Capital Markets is of the view that the proportion of corporate trading volumes relative to outstanding corporate bonds (or bid/offer indications) are sufficiently high that liquidity premiums are not required by the market for the corporate and utility bonds used to develop its Canadian generic A-rated corporate and utility bond spreads.[273]

268 Transcript, page 3357 lines 3-7.
269 Transcript, page 3148 lines 8-14.
270 Revised Evidence of Dr. Booth, Exhibit 292.03, pages 88-95.
271 Revised Evidence of Dr. Booth, Exhibit 292.03, page 95.
272 Engen Rebuttal Evidence, Exhibit 279.01, page 19.
273 Engen Rebuttal Evidence, Exhibit 279.01, page 20.

308. As has occurred throughout this Proceeding, the Commission must weigh conflicting expert testimony on various factors impacting the determination of a fair return for Alberta utilities. The Commission considers the increased high grade Canadian corporate bond spreads which occurred during the financial crisis and which continued to occur, albeit on a downward trend, at the close of the Proceeding demonstrate that there has indeed been some re-pricing of risk on debt securities. Equity investors in high grade rated companies have more default risk than do debt investors. An increase in debt investor return expectations ordinarily must be considered to result in an increase in return expectations for equity investors otherwise equity investors would not accept the incremental risk associated with equity ownership. The Commission finds that there is insufficient evidence on the record of the proceeding that illiquidity in the Canadian bond market during the financial crisis can account for a significant portion of the increased risk premium demanded by bond investors.

309. While high grade Canadian corporate bond spreads have declined materially since the peak of the financial crisis, the evidence available at the close of the proceeding indicated that some degree of increased corporate bond spread continued compared with pre-financial crisis levels. As described by Mr. Engen above, the high grade Canadian corporate bond spread prior to 2007 averaged 125 basis points[274]. At the close of the oral hearing, CAPP stated “Generic corporate bond spreads had come down to about 200 basis points in early June with utility bond spreads at 170, 175 basis points.”[275] It appears that corporate bond spreads remained at the close of the Proceeding approximately 50 basis points higher than pre-financial crisis levels.

310. The Commission notes the observation of Dr. Booth in the following exchange with counsel for the ATCO Utilities that 50 basis points is the approximate level of “excess spread” required in the debt market for high grade Canadian utility bonds at the time of the oral hearing.

> Right now the yields on utility debt in Canada are down to 170, 175 basis points. The yields on CU debts (sic) below that, about 168 basis points. That was as of last week and they’ve been dropping 10, 20 basis points in the last week or so. So what’s happening is utility spreads are tightening dramatically. What I would expect, given that where we are in the economy, I would expect those utility spreads to be more like 125 basis points. So I would guess there’s still about a 50 basis point, what I would regard as excess spread. And most of the people writing newsletters are saying there’s still value to be had in buying corporate bonds.[276]

311. It remains an open question whether corporate bond spreads will quickly, if ever, return to pre-financial crisis levels. In particular, it remains uncertain that the re-pricing of risk observed in high grade Canadian corporate bond spreads in the period up to the close of the Proceeding will end in either 2009 or 2010. In these circumstances, it is reasonable to conclude that the actual return expectations of utility equity investors in 2009 and 2010 would be at least 50 basis points higher than estimates of equity return expectations derived from methodologies like CAPM which rely solely upon historical data and the risk free rate.

[274] Coyne Rebuttal Evidence, Exhibit 279.01, page 3.
[275] CAPP Written Argument, Exhibit 388.02, pages 6-7.
[276] Transcript, pages 3218-3219.

5.8 Pension, Investment Manager and Economist Return Expectations

312. In Decision 2004-052, the Board considered evidence on the expectations of pension and investment managers. There was relatively little evidence of, or discussion on, the expectations of pension and investment managers in this proceeding.

313. The UCA argued that the Commission should accept survey results from pension and investment managers and other knowledgeable sources as valid benchmarks against which ROE or MERP recommendations can be assessed.[277] Specifically, the UCA referred to the evidence of Drs. Kryzanowski and Roberts, who used the return expectations from surveys of professional economists and portfolio managers provided by Watson Wyatt. The UCA stated that the most recent forecasts collected by Watson Wyatt reported median total return expectations of 7.5 percent for the S&P/TSX Composite Index for both the mid-term (2010-2013) and long-term (2014-2023).[278] They concluded that the ROE recommendation of 7.9 percent for 2009 from Drs. Kryzanowski and Roberts is conservatively high.[279]

314. Mr. Engen indicated that, from his discussions with the major Canadian pension funds, he understood that pension funds expect energy infrastructure investment returns on capital in the order of a minimum of 7.5 percent to 8.5 percent with returns on equity in the range of 10.0 percent to 12.0 percent.[280] ATCO argued that this evidence demonstrates that potential investors in infrastructure are looking for returns that are significantly higher than recommended by Drs. Kryzanowski and Roberts. However, the Commission finds that the evidence of Mr. Engen, on pension fund expectations, is anecdotal and cannot be relied upon.

315. With respect to the Watson Wyatt evidence relied upon by Drs. Kryzanowski and Roberts, the Commission takes this as one indication that professional economists and portfolio managers expect that returns for the market as a whole may decline, over the medium to long run, once the effects of the financial crisis have dissipated. At issue for the Commission, however, is the speed at which the effects of the financial crisis will indeed abate.

5.9 Negotiated Settlements

316. There was no suggestion by any party to the proceeding that the Commission should take any guidance from the results of recently negotiated general rate application settlements when establishing a fair return for the utilities. The UCA recommended that the Commission not place any weight on negotiated settlement evidence presented in this proceeding, and that all negotiated settlements cannot be used to set any precedents because they are made up of a series of compromises.[281]

317. CAPP argued that the Commission should not have regard to negotiated settlements because:

> … settlements involve tradeoffs. Using negotiated agreements as precedents would take agreements negotiated as package deals and that are only acceptable to the parties as a complete package and cherry pick one item, the return opportunity, as the precedent. It would completely chill the freedom to negotiate within established regulatory

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[277] UCA Argument, Exhibit 387.01, page 38.
[278] Ibid.
[279] UCA Argument, Exhibit 387.01, page 38.
[280] Exhibit 52.02, Engen Evidence, page 85.
[281] UCA Argument, Exhibit 387.01, page 90.

> frameworks if those same agreements were used as precedents to ratchet or re-jig the regulatory framework itself. That would turn without prejudice agreements into with prejudice agreements. Finally, the confidential nature of such negotiations prevents any ability to look through the agreements and see all the tradeoffs being made.[282]

318. ATCO, in response to a question from Mr. McNulty with respect to the relevance of the recently negotiated ATCO Pipelines settlement, appeared to agree with the interveners on this matter.

> The suggestion that the settlement could be taken as evidence that ATCO Pipelines considered a lower ROE to be a fair return is, with respect, improper and lacks balance, unfairly prejudicing the utility. The language in the settlement is perfectly clear that the return and capital structure, which were deemed values for purposes of the settlement, could not be taken as precedential or prejudicial to positions taken, specifically, in this generic cost of capital proceeding.[283]

319. The Commission agrees with parties that negotiated general rate applications settlements cannot be considered in setting the allowed ROE for a utility, because they are made up of a series of compromises and are not of assistance in determining the expected market return for a stand-alone utility.

5.10 Expected Canadian Average Stock Market Returns

320. Dr. Booth's forward looking ROE for the Canadian equity market was developed by assuming that the average dividends since 1961 for the TSX, at 2.4 percent of GDP, and after tax corporate profits of 6.4 percent, imply an average real Canadian growth rate since 1961 of approximately 3.53 percent. Dr. Booth assumed that the "Bank of Canada's inflation rate forecast of 2.0%, implying a long-run growth rate in dividends and earnings of about 5.60%."[284] He then added the assumed long run growth rate to the current dividend yield on the TSX of 4.04 percent to derive a DCF estimate of approximately 10.0 percent. However, Dr. Booth argued that this result over-estimates the required rate of return because "short run growth prospects are considerably poorer than the long run rate."[285] To counteract this he applied a two-stage growth model where the current dividend is expected to be constant for the first two years then recover in 2010, at which time the growth rate is assumed to be the long run growth rate of 5.60 percent. As a result, Dr. Booth estimates a return on the S&P/TSX of 9.25 percent.

321. Dr. Vander Weide disagreed with Dr. Booth's application of the DCF method to the Canadian market as a whole stating the assumptions of the DCF model do not apply to the Canadian market as a whole. He reasoned that the DCF model is based on the fundamental assumption that a company's stock price is equal to the present value of the cash flows investors expect to receive from investing in the company's stock, that it is very difficult, if not impossible, to match stock prices and cash flows for the Canadian market as a whole, and that the DCF model cannot be applied to companies in the Canadian market that do not pay dividends. The TSX includes companies that do not pay dividends and the TSX companies may

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282 CAPP Argument, Exhibit 388.02, page 35.
283 ATCO Argument, Exhibit 390.02, page 105.
284 1.02*1.0353.
285 Dr. Booth Revised Evidence, Exhibit 292.03, page 101.

grow for many years at a growth rate that is significantly different from that of the Canadian economy.[286]

322. The Commission rejects Dr. Vander Weide's concerns that Dr. Booth's application of the DCF method to the Canadian stock market as a whole is fundamentally flawed. The Commission finds Dr. Booth's forecast to be reasonable, and will take it into consideration in its determination of the utilities' required ROE because all that is required to calculate returns using the DCF model is an initial dividend yield and justifiable short- and long-term forecast dividend growth rate.

5.11 The Commission's Awarded ROE

323. The Commission is required to establish a fair rate of return on equity for 2009 and going forward for the utility companies it regulates. 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 analysis 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 determinations. All of the Commission's analysis has been conducted in the context of, and having regard to, the uncertainties created by the current financial crisis that began in the third quarter of 2007.

324. The generic ROE established by the Board in 2004 and the annual adjustment formula adopted at that time were developed based on the assumption that certain key relationships in the financial markets would continue. In particular, the Board relied on CAPM as the primary basis for the 2004 awarded ROE and annual adjustment formula. As explained in Section 7 of this Decision the Commission accepts that, during the current financial crisis, the traditional relationship between the risk free rate (measured as the yield on long Canada bonds) and the required market return on equities has not continued. Therefore, the Commission has found it necessary to make certain adjustments to its CAPM analysis and also considered some of the DCF analysis, as well as other factors in arriving at a fair ROE.

325. Based on the Commission's findings with respect to CAPM, the Commission found a reasonable range of CAPM results of 7.13 percent to 8.62 percent. However, given the Commission's observations with respect to the impacts of the financial crisis on the traditional relationships in the financial market, the Commission considers that these CAPM may be unreasonably low.

326. The Commission's analysis of the performance of high grade bonds relative to the risk free rate during the financial crisis, as explained in Section 5.7, reveals that the traditional spread between the long Canada bond yield and the yield on high grade bonds had increased to well above the traditional spread of one percent and by the close of the record in the proceeding had moved back to a spread of approximately 1.5 percent. As a result, the Commission concludes that the CAPM results likely underestimate the required market equity return by at least 50 basis points. Accordingly, the Commission has adjusted its CAPM results to arrive at a range of 7.63 percent to 9.12 percent.

[286] Exhibit 282.01, Dr. Vander Weide Rebuttal Evidence, pages 55-56.

327. The Commission has also considered some of the DCF results on the record of this proceeding to be relevant to its consideration of a fair rate of return. In doing so, the Commission is mindful of some of the shortcomings of DCF expressed by parties. Specifically, the Commission is concerned that it is necessary to perform the analysis on proxy companies that may have significant unregulated assets. In addition the Commission recognizes that the DCF analysis depends on potentially optimistic forecasts of financial analysts. Nevertheless, the Commission does have DCF results for two Canadian utility holding companies with close to one hundred percent of their assets in regulated businesses. Dr. Vilbert's multi-stage DCF analysis for these two companies (Emera Inc. and Fortis Inc., which were part of his Canadian proxy group) yielded results of 8.80 percent and 9.20 percent respectively.[287] The Commission also examined the results of multi-stage DCF studies provided by Dr. Vilbert for his Canadian proxy group and two U.S. proxy groups. These results gave the Commission comfort that the DCF results for Emera Inc. and Fortis Inc. are reasonable. The Commission finds the DCF results for these two companies instructive because the companies closely resemble stand-alone regulated utilities. Overall the Commission found that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 percent to 9.3 percent, assuming that the equity ratio has been set to target a credit rating in the A range.

328. The Commission also considered the evidence of Dr. Vander Weide on the historical returns for the TSX from 1956 to 2008 which determined that the average stock market return over that period was 10.30 percent. This result largely mirrored the analysis of Dr. Booth that estimated the historical return on the TSX at 10.14 percent.[288] The Commission also considered Dr. Booth's forward-looking DCF analysis of the expected average stock market return for the S&P/TSX, which showed a result of 10 percent, which Dr. Booth adjusted downward to 9.25 percent on the assumption that the returns for the first two years of his study period would be depressed.[289] The Commission recognizes that stand-alone utility companies, because of their relatively low risk, would be expected to earn returns over the long run that are lower than the expected return for the overall Canadian stock market. This conclusion is supported by the fact that every expert witness in the Proceeding recommended a beta of less than one. In addition, the Commission notes that Mr. Engen, appearing for the ATCO Utilities, when discussing the requests of the utilities in this proceeding stated that "… I don't think anybody is looking to achieve the same kinds of returns long term or otherwise that you would expect in the marketplace generally."[290] Accordingly, the Commission considers that it would be unreasonable to award stand-alone utilities an ROE in excess of 9.775, being the midpoint of the range of 9.25 percent to 10.30 percent.

329. The Commission recognizes that monopoly utility companies are generally considered by many to be relatively low risk investments. The Commission heard evidence during the Proceeding that the non-utility company share values fluctuated significantly during the financial crisis while the shares for utility holding companies remained fairly stable.[291] In the Commission's view, this demonstrates that the utility holding companies are perceived by investors to have less risk than non-utility holding companies. This conclusion is borne out by the fact that the unadjusted beta for utility holding companies during the peak of the financial

287 These numbers include a floatation allowance of .50 added by the Commission.
288 Dr. Booth Revised Evidence, Exhibit 292.03, page 85.
289 Dr. Booth Revised Evidence, Exhibit 292.03, page 101.
290 Transcript, page 1511.
291 Dr. Booth Revised Evidence, Exhibit 292.03, page 80 and Mr. Engen, Exhibit 310.

crisis dropped to very low levels.[292] It follows that stand-alone utilities would have less risk than the utility holding companies and therefore must have even lower betas.

330. The Commission is mindful that evidence on professional economists' and portfolio managers' expectations suggests that returns for the market as a whole may decline over the medium to long run once the effects of the financial crisis have dissipated. The Commission also recognizes that there remains a considerable amount of uncertainty in the financial markets and the Commission is concerned that awarding a generic ROE that does not take these uncertainties into account would be unreasonable.

331. Having considered and weighed all of the evidence and assessed it in the context of the current financial crisis, it is the Commission's judgment that the generic ROE for 2009 should be set at 9.0 percent.

6 CAPITAL STRUCTURE

6.1 Introduction

332. 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 9.0 percent which will be applied uniformly to all of the utilities. As the Board did previously, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures.

333. 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. 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. 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 Dominion Bond Rating Services (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 both cover its debt obligations and pay a return to its shareholders.

334. In this Decision, the Commission will establish, for each utility, the capital structure 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 record of the Proceeding on the overall risk of regulated utilities posed by the current credit environment and current utility credit metrics. The Commission will then assess, on the basis of the record of the Proceeding, the risk of each of the utility sectors and determine a relative ranking of risk for each sector and the commensurate equity ratio that, in the Commission's judgment, will allow the utilities in each sector to maintain the desired credit

[292] Dr. Booth Revised Evidence, Exhibit 292.03, page 73.

rating. 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.

335. The following table (grouped by sector) compares the equity ratios that were approved by the Board in Decision 2004-052 (and in the case of EEAI, in its most recent GTA) with the equity ratios recommended by the applicants and interveners in this Proceeding.

Table 11. Recommended Equity Ratios vs. Last Board Approved Equity Ratios

	Last Approved (%)	Recommended by Utility[293] (%)	Recommended by UCA & CCA[294] (K&R) (%)	Recommended by Calgary[295] (Booth) (%)	Recommended by CAPP[296] (Booth) (%)
Electric and Gas Transmission					
ATCO Electric TFO	33.0	38.0	33.0	<35.0	
AltaLink	33.0	38.0	33.0	<35.0	
ENMAX TFO	35.0	40.0	30.0		
EPCOR TFO	35.0	40.0	30.0		
ATCO Pipelines	43.0	43.0	42/34[297]		37/33[298]
Electric and Gas Distribution					
ATCO Electric DISCO	37.0	40.0	35.0		
ENMAX DISCO	39.0	44.0	35.0		
EPCOR DISCO	39.0	44.0	35.0		
ATCO Gas	38.0	40.0	34.0	35.0	
ATCO Gas for 2008	38.0	40.0	38.0[299]		
FortisAlberta	37.0	42.0(+ 2)[300]	35.0		
AltaGas	41.0	46.0	40/37[301]	40.0	
Retailers					
EEAI	37[302]	42.0	35.0		

336. The CCA did not sponsor evidence but, in argument, supported the equity ratios submitted by Drs. Kryzanowski and Roberts. Calgary indicated in argument that it generally supported the positions taken by the UCA. CAPP submitted in argument that it had limited its capital structure recommendation to ATCO Pipelines.

6.2 Credit Environment

337. During the hearing, evidence was introduced by the utilities and generally accepted by the interveners regarding the financial crisis that affected the world beginning late in 2007. The parties, however, disagreed over whether the crisis had ended or whether there were some lingering and potentially long-term effects.

293 ATCO Evidence, Exhibit 50.01, page 5, Dr. Vander Weide Joint Evidence, Exhibit 57.04, page 37, Dr. Vilbert, Exhibit 58.02, page 24, ENMAX Evidence, Exhibit 55.01, page 6.
294 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 6.
295 Calgary Argument, Exhibit 386.02, pages 12-13.
296 CAPP Argument, Exhibit 388.02, page 94.
297 42.0 percent without NGTL Integration Agreement, 34.0 percent with NGTL Integration Agreement.
298 37.0 percent without NGTL Integration Agreement, 33.0 percent with NGTL Integration Agreement.
299 UCA Argument, Exhibit 387.01, page 97.
300 42.0 percent Recommended by Dr. Vander Weide, 44.0 percent Requested by FortisAlberta for non-taxable status.
301 40.0 percent without weather deferral account, 37.0 percent without weather deferral account.
302 Exhibit 53.04, Evidence of Dr. Vander Weide, page 37.

338. Interveners argued that "since the dark days when interveners filed their evidence, there have been significant improvements in capital markets."[303] They pointed to a number of improving financial and economic indicators that supported their claims. Hence, the Commission, the interveners urged, "should not be concerned with the allegations that any problems raising capital are not short term."[304]

339. The utilities argued that what the world experienced in terms of economic and financial meltdown was something of an unprecedented nature that fundamentally altered the perception of risk and that it will have long-term consequences. ATCO, for example, argued that "[e]quity risk has been re-priced pure and simple."[305] Furthermore, citing Mr. Coyne's rebuttal evidence, ATCO argued that "the faith of investors has been severely shaken by the sudden downturn in equity valuations and dislocations in the financial system, and such shifts in investor sentiment may take years or decades to return to 'normal'."[306]

340. AltaGas also argued that even though "the worst of the crisis is perhaps behind us," risk-averse investors have not restored their confidence in the market to where they were before the crisis.[307] Similarly, AltaLink's Mr. Bronneberg testified at the hearing that the capital markets "are still under tremendous pressure and remain volatile and unpredictable."[308] In a cautionary fashion, he warned that given the nature of the financial crisis, "another unexpected event could trigger a material reversal in this recovery."[309]

341. In light of this and other exchanges during the hearing, the Commission accepts that the financial markets have not returned to typical pre-2007 behavior, and the long term effects of the crisis, ranging from the continued elevated corporate bond spreads, short-term interest rates close to zero, the rapidly increasing size of government deficits, and the continuing job losses in the U.S., are still present.[310]

342. The Commission must also consider that the events that drove the original crisis will be factored into investors' perceptions. Companies will therefore protect their balance sheets and investors will adjust risk perceptions whether unexpected events present themselves again or not. In order to protect investors' and ratepayers' interests, the Commission must award equity ratios that recognize the need for the ongoing viability of the utility even in adverse conditions. Therefore, the Commission will increase allowed equity ratios.

6.3 Credit Metrics and Actual Credit Ratings

343. 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.

303 CAPP Argument, Exhibit 388.02, paragraph 274.
304 UCA Argument, Exhibit 387.01, page 83, paragraph 379.
305 ATCO Argument, Exhibit 390.02, page 48, line 14.
306 ATCO Argument, Exhibit 390.02, page 48, lines 20-23.
307 AltaGas Reply Argument at page 8.
308 Transcript at page 201, lines 2-4.
309 Transcript at page 201, lines 5-6.
310 See paragraph 46 above.

344. A number of Canadian utility companies finance their debt requirements directly in the debt market independently of any affiliated companies, thereby ameliorating the "dirty window" challenges. Therefore, the Commission will examine the credit ratings of such 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 Canadian utility.

345. There are three principal credit metrics. They are:

- EBIT Coverage (interest coverage ratio), which is the company's earnings measured before deducting interest and taxes divided by total interest costs;
- FFO/Debt, which is the company's funds from operations as a percentage of total debt;
- FFO Coverage, which is the company's funds from operations divided by total interest costs.

346. The utilities argued that it was necessary for their companies to meet or exceed minimum standards for these metrics in order to maintain a credit rating in the A range. The utilities pointed to some minimum credit metrics published by the bond rating agencies as providing guidance to the Commission.[311] The Commission observes that these "minimum credit metrics" are more in the nature of general guidelines and that they are no longer consistently published by credit rating agencies.[312]

347. The following table provides the actual credit ratings and corresponding key financial ratios (or credit metrics) for the Canadian utility companies that raise debt independently and for which credit reports were available on the record. The Commission did not include government-owned entities in this table because their credit ratings are heavily influenced by their government ownership status.

[311] Testimony of Susan Abbott, Exhibit 57.05, page 8, lines 148-150.
[312] Ibid. page 16, line 317 to page 17, line 319.

Table 12. Credit Rating Metrics

Segment or Utility	Actual Debt Rating(s)	Provider	EBIT Interest Coverage	FFO / Debt (%)	FFO Coverage
AltaLink[313]	A- Stable	S&P	1.7	11.1	3.0
AltaLink[314]	A Negative Trend	DBRS	2.07		
AltaLink Investments L.P.[315] (Parent of AltaLink)	BBB Negative Outlook	DBRS	1.53	10.5[316]	
Fortis Inc.[317]	A-	S&P	2.2	11.5	2.9
FortisAlberta[318]	A (low)	DBRS	2.03		
FortisAlberta[319]	A-	S&P	2.3	14.3	4.2
CU Inc.[320]	A	S&P	2.7	18.7	3.6
CU Inc.[321]	A (high)	DBRS	2.38		

348. The Commission observes from the above table that EBIT coverage ratios of approximately 2.0 to 2.3 appear to be sufficient to obtain credit ratings in the lower A range.

349. EPC submitted that based on S&P guidelines, an interest coverage ratio of 2.3 to 2.8 is required to maintain an A credit rating for "S&P business risk positions 2 to 3" which would be applicable to the distribution business of EPC, and an interest coverage ratio of 1.8 to 2.3 times is required for the lower risk "S&P business risk position of 1 to 2" which would be applicable to the transmission business of EPC. The "business risk positions" to which EPC referred, are business risk rankings formerly employed by S&P. S&P no longer publishes business risk positions. Nevertheless, the Commission observes that if S&P were still using the guidelines cited by EPC, it appears that all of the utilities listed in Table 7 (all of which have investment grade ratings) would be considered in a lower risk category given that their EBIT coverage ratios range from 1.7 to 2.7. In the case of AltaLink Investments L.P., DBRS has assigned a credit rating of BBB with a negative outlook where the EBIT coverage ratio is 1.53 times and the "cash flow to debt" (a term used by DBRS that appears to be equivalent to FFO/Debt) is 10.5 percent. This gives the Commission some indication that the lower end of the EBIT coverage range necessary to maintain a credit rating in the A range is approximately 1.8.

350. Below, the Commission reviews its analysis of the sensitivity of three key credit rating metrics to changes in the equity ratio. The Commission notes that the credit rating metrics are not very sensitive to changes in the ROE. Credit metrics are more sensitive to the amount of debt and equity in the capital structure than they are to the return on equity.

6.3.1 EBIT Interest Coverage Ratio

351. The Commission has calculated and set out in Table 13 below, interest coverage ratios that would result from different equity ratios assuming an embedded cost of debt of 6.5 percent,

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313 Exhibit 57.06, pages 25 to 35 of 83, S&P credit report dated May 9, 2008.
314 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report of May 28, 2008.
315 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report dated May 28, 2008.
316 DBRS described this number as measuring cash flow/debt, which appears to be the same as FFO/Debt.
317 Exhibit 53.05, S&P credit report October 25, 2007 and Fortis Inc. Balance Sheet, page 107 of 283.
318 Exhibit 53.05 FortisAlberta Minimum Filing Requirements, section 4, DBRS credit report, May 30, 2008.
319 Exhibit 53.05 FortisAlberta Minimum Filing Requirements, section 4, S&P credit report, March 26, 2008.
320 Exhibit 50.02, CU Inc. S&P report dated October 26, 2007.
321 Exhibit 50.02, CU Inc. DBRS report dated May 13, 2008.

an ROE of 8.75 percent (the 2009 placeholder level) and assuming an income tax rate of 29 percent.[322] The assumed debt cost is conservative for 2009 because, according to the utility reports on finances and operations provided in the minimum filing requirements, the average cost of debt in 2007 was 6.22 percent.

Table 13. EBIT Interest Coverage Ratios Compared to Equity Ratios

Equity Ratio (%)	EBIT Interest Coverage
30	1.8
31	1.9
32	1.9
33	1.9
34	2.0
35	2.0
36	2.1
37	2.1
38	2.2
39	2.2
40	2.3
41	2.3
42	2.4
43	2.4
44	2.5
45	2.6

352. Table 13 shows that at a 6.5 percent cost of debt, the minimum equity ratio to achieve a 2.0 EBIT coverage ratio is 34 percent. The table also shows that to achieve an EBIT coverage ratio of 2.3 with a 6.5 percent embedded debt cost would require a minimum equity ratio of 40 percent.[323] The Commission has compared the results shown in Table 13 to the results shown in Table 9 of EUB Decision 2004-052[324] and observes that the equity ratio required in 2004 to obtain a given EBIT coverage ratio is lower than the equity ratio required today to achieve the same EBIT coverage ratio. The equity ratio required today is higher than in 2004 because income tax rates and allowed ROE declined during the period. For example, achieving an EBIT coverage ratio of 2.0 in 2004 at a 6.5 percent embedded cost of debt would have required a 30 percent equity ratio, whereas in 2009 it would require an equity ratio of 34 percent. The Commission recognizes that lower debt costs would lower the required increase in the equity ratios. Testimony given during the hearing indicated that the average cost of debt has declined since 2004 which would somewhat offset the required increase in the equity ratios indicated here.

[322] Transcript, page 1870.

[323] The Commission recognizes that the required equity ratio to achieve the interest coverage levels in the table would be somewhat higher in the presence of CWIP or when the effective tax rate is lower than 29 percent due to the Commission's use of the flow-through tax method for revenue requirement purposes in the case of some utilities.

[324] EUB Decision 2004-052, Table 9 entitled Pretax Interest Ratios at Varying Embedded Debt Costs, shown at page 41.

6.3.2 Funds From Operation/Debt Ratio

353. The Commission has also calculated, and set out in Table 14 below, the ratio of the Funds From Operations (FFO) (net income plus depreciation) divided by debt that would result[325] at different equity ratios assuming an ROE of 8.75 (the 2009 placeholder level) and assuming a range of depreciation rates (as a percentage of invested capital) from 4 percent to 9 percent based on actual depreciations rate results calculated from the 2007 reports on finances and operations. These range from 4.8 percent to 8.5 percent and average 6.0 percent.

Table 14. Funds From Operations to Debt Compared to Equity Ratios

Depreciation Rate	4.00%	5.00%	6.00%	7.00%	8.00%	9.00%
Equity Ratio (%)						
30	9.5	10.9	12.3	13.8	15.2	16.6
31	9.7	11.2	12.6	14.1	15.5	17.0
32	10.0	11.5	12.9	14.4	15.9	17.4
33	10.3	11.8	13.3	14.8	16.3	17.7
34	10.6	12.1	13.6	15.1	16.6	18.1
35	10.9	12.4	13.9	15.5	17.0	18.6
36	11.2	12.7	14.3	15.9	17.4	19.0
37	11.5	13.1	14.7	16.3	17.8	19.4
38	11.8	13.4	15.0	16.7	18.3	19.9
39	12.2	13.8	15.4	17.1	18.7	20.3
40	12.5	14.2	15.8	17.5	19.2	20.8
41	12.9	14.6	16.3	17.9	19.6	21.3
42	13.2	15.0	16.7	18.4	20.1	21.9
43	13.6	15.4	17.1	18.9	20.6	22.4
44	14.0	15.8	17.6	19.4	21.2	22.9
45	14.4	16.3	18.1	19.9	21.7	23.5

354. Table 14 shows that when the annual depreciation expense as a percentage of invested capital is equal to the utility average of 6 percent, minimum equity ratios in the range of 30 to 36 percent will achieve FFO/Debt percentages of 11.1 to 14.3, which Table 12 shows is associated with credit ratings in the lower A range.[326]

6.3.3 Funds From Operations Coverage Ratio

355. The Commission has calculated, and set out in Table 15, the coverage ratio of the Funds From Operations (net income plus deprecation) divided by interest expense that would result at different equity ratios and depreciation rates assuming an ROE of 8.75 percent (the 2009 placeholder level) and an embedded interest cost of 6.5 percent.

[325] The Commission recognizes that this is theoretical since it omits consideration of CWIP (which lowers the FFO/ debt ratio when present) and does not consider that some utilities actually collect more taxes than paid in cash which increases the FFO/Debt ratio.

[326] This omits consideration of CWIP or cash flows created by positive or negative differences between tax collected and tax paid.

Table 15. Funds From Operations Coverage Compared to Equity Ratios

Depreciation Rate	4.00%	5.00%	6.00%	7.00%	8.00%	9.00%
Equity Ratio (%)						
30	2.46	2.68	2.90	3.12	3.34	3.55
31	2.50	2.72	2.94	3.17	3.39	3.61
32	2.54	2.76	2.99	3.22	3.44	3.67
33	2.58	2.81	3.04	3.27	3.50	3.73
34	2.63	2.86	3.09	3.33	3.56	3.79
35	2.67	2.91	3.14	3.38	3.62	3.86
36	2.72	2.96	3.20	3.44	3.68	3.92
37	2.77	3.01	3.26	3.50	3.74	3.99
38	2.82	3.07	3.31	3.56	3.81	4.06
39	2.87	3.12	3.37	3.63	3.88	4.13
40	2.92	3.18	3.44	3.69	3.95	4.21
41	2.98	3.24	3.50	3.76	4.02	4.28
42	3.04	3.30	3.57	3.83	4.10	4.36
43	3.10	3.37	3.63	3.90	4.17	4.44
44	3.16	3.43	3.71	3.98	4.26	4.53
45	3.22	3.50	3.78	4.06	4.34	4.62

356. It appears from Table 15 that when the annual depreciation expense as a percentage of investment capital is equal to the utility average of 6 percent, a minimum equity ratio of 33 percent is required to achieve an FFO coverage ratio of at least 3, which Table 7 shows is the minimum FFO coverage associated with credit ratings in the lower A range.

6.4 Credit Rating Metric Conclusions

357. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta Utilities should be 34 percent based on EBIT analysis, (which is 1 percentage point higher than the existing level awarded to transmission companies), 30 to 36 percent based on FFO/Debt analysis and 33% based on FFO interest coverage analysis; (ii) as a result of lower income tax rates and lower ROEs, a 4 percentage point equity ratio increase would be required to maintain credit metrics at the same level as the 2004 levels; and (iii) the 4 percentage points equity ratio increase would be offset to some degree by the lower debt costs in 2009 versus 2004.

6.5 Equity Ratios and Actual Credit Ratings

358. This section examines the actual credit ratings achieved by Canadian regulated utilities and the equity ratios associated with such credit ratings. The Commission considers that this information provides important factual evidence regarding the equity ratios required for a regulated utility to achieve its actual reported credit ratings. The following table has been prepared by the Commission from information on the record to assist in the analysis. In the table, the Commission has included utilities that are comparable to the utilities regulated by the Commission and that raise their debt independently of an affiliate and for which credit information was available on the record. The Commission did not include government-owned entities.

Table 16. Summary of Canadian Utility Credit Ratings and Equity Ratios

Segment or Utility	Actual Debt Rating(s)	Provider	Equity %	Nature of Rating.	Nature of Business
AltaLink[327]	A- Stable	S&P	36.3	Stand-alone	fully regulated
AltaLink[328]	A Negative Trend	DBRS	38.4	Stand-alone	fully regulated
AltaLink Investments L.P.[329] (Parent of AltaLink)	BBB Negative Outlook	DBRS	27.2	Stand-alone	fully regulated
Fortis Inc.[330]	A-	S&P	32.9	Stand-alone	Largely regulated
FortisAlberta[331]	A (low)	DBRS	39.5	Stand-alone	fully regulated
FortisAlberta[332]	A-	S&P	36.4	Stand-alone	fully regulated
CU Inc.[333]	A	S&P	41.0	Rating factors in parent support	fully regulated
CU Inc.[334]	A (high)	DBRS	39.1	Stand-alone	fully regulated
Newfoundland Power[335]	A	DBRS	44.1	unknown	fully regulated

359. Table 16 shows that the actual equity ratios of the companies with a credit rating of A- or better range from 32.9 percent to 44.1 percent with a mid point of 38.5 percent.

360. Other information about equity ratios and related credit ratings was provided on the record by Dr. Neri, on behalf of EPC. He submitted that based on his "Canadian Wires-only Peer Group," the median credit rating was "A" and the actual equity ratios ranged from 38.1 percent to 59.6 percent with the median for the group being 44.1 percent[336] (and the midpoint being 48.8 percent). The Commission notes however that Dr. Neri's seven utilities included four government-owned utilities (Hydro One, Hydro Ottawa Holdings, Toronto Hydro and Viridian Corporation). The Commission agrees with those parties (including utilities) that expressed doubts about the usefulness of data that includes the equity ratios and the credit ratings of government-owned utilities for the purposes of a proceeding dealing with investor-owned utilities.[337] Therefore, the Commission does not consider Dr. Neri's equity ratio range to be representative of stand-alone investor-owner utilities.

361. As set out in Table 11, the utilities have applied for equity ratios ranging from 38 percent (AltaLink and ATCO Electric Transmission) to 46 percent (AltaGas) and argued that these equity ratios are needed to ensure credit ratings in the A range.

327 Exhibit 57.06, pages 25 to 35 of 83, S&P credit report dated May 9, 2008, indicates a debt /(debt and equity) ratio of 63.7 percent and states that "[h]owever, the company does carry C$200 million in goodwill on its balance sheet; a more conservative measure of leverage relative to rate base is about 70%."

328 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report of May 28, 2008.

329 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report dated May 29, 2008, AILP's consolidated debt to capital is indicated as 72.8 percent (and the Commission notes that this is with no adjustment for goodwill).

330 Exhibit 53.05, S&P credit report October 25, 2007 and Fortis Inc. Balance Sheet, page 107 of 283.

331 Exhibit 53.05, FortisAlberta Minimum Filing Requirements, section 4, DBRS credit report, May 30, 2008.

332 Exhibit 53.05, FortisAlberta Minimum Filing Requirements, section 4, S&P credit report, March 26, 2008.

333 Exhibit 50.02, CU Inc. S&P report dated October 26, 2007.

334 Exhibit 50.02, CU Inc. DBRS report dated May 13, 2008.

335 Exhibit 55.01, Evidence of Dr. Neri, Schedule 1.

336 Exhibit 55.01, Evidence of Dr. Neri, page 26 of 26.

337 Dr. Neri also included a DBRS credit rating for Newfoundland Power and referenced its credit reports and financial statements.

362. In conducting its analysis, the Commission has observed that credit rating agencies typically adjust the debt/equity ratios of companies to account for items such as asset retirement obligations and capitalized leases. In some cases, adjustments are also made for goodwill. Goodwill on the balance sheet of a utility company may arise when a utility is purchased by another entity at an amount that exceeds its rate base value. The results of these adjustments are important to consider for utility companies because utility regulators do not award a rate of return on goodwill. In the case of TransCanada Pipelines the Moody's credit rating[338] focused on a debt or equity ratio excluding goodwill. As noted in footnote 328, in the case of AltaLink, S&P indicated that after excluding goodwill from the balance sheet "a more conservative measure of leverage to rate base is approximately 70 percent" (30 percent equity).[339] As shown in Table 11, AltaLink has an equity ratio of 36.3 percent (according to S&P) and 38.4 percent (according to DBRS) and has a credit rating of A- stable (S&P) and A with negative trend (DBRS). As noted in footnote 328, S&P subtracted $200 million in goodwill from AltaLink's balance sheet thereby estimating an equity ratio of 30 percent which is 3 percentage points lower than the awarded equity ratio (even though AltaLink on an unadjusted basis has an equity ratio above its awarded 33 percent).

363. In the same table DBRS indicates that FortisAlberta had an equity ratio of 39.5 percent and had a credit rating of A (low). S&P indicated an equity ratio of 36.4 percent and an A- credit rating for FortisAlberta. This compares to an awarded equity ratio of 37 percent. S&P indicated in its FortisAlberta credit report provided in Exhibit 53.05, that if an asset retirement obligation is treated as debt and if capitalized operating leases are considered then the debt to total capital ratio is 70 percent (which implies a 30 percent equity level). This adjustment does not include any reduction for goodwill similar to the reduction S&P discussed for AltaLink. If such an adjustment were made, the FortisAlberta equity ratio would be 27.8 percent,[340] 9 percentage points below its awarded equity ratio.

364. These observations suggest that if AltaLink and FortisAlberta (or other utilities) had not had goodwill on their balance sheets, then their equity ratios would have been somewhat lower than their current levels but would still have been sufficient to generate financial metrics necessary to maintain their current credit ratings.

6.6 Ranking Risk by Regulated Sector

365. In 2004, the EUB 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. Credit rating agencies take into account business risks, and therefore the equity ratios associated with the credit ratings of various utilities provide a good indication of the market's view of the equity ratios required.

366. A number of witnesses commented on the relative risk of the various utility sectors. Dr. Booth expressed the view that electric transmission remains the lowest risk.[341] Ms. Abbott,

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[338] Exhibit 52.03, page 78 of 348, Moody's credit rating report.
[339] Exhibit 57.06, S&P Credit Report dated May 9, 2008.
[340] The Commission calculated the adjusted equity ratio from page 7 of the May 30, 2008 DBRS credit report by excluding goodwill i.e. (460-189)/(460-189+696+8) =0.280.
[341] Booth Revised Evidence, Exhibit 292.03, page 62, lines 13-19, pages 57-59.

appearing for AltaLink, stated that transmission and distribution companies are regarded as having similar business risk."[342]

367. Mr. Johnson, witness for Calgary, submitted that the least risky entities are the electric transmission companies AltaLink and ATCO Electric Transmission. Mr. Johnson rated gas and electric distribution as slightly more risky than electric transmission and the municipal owned companies more risky than gas and electric distribution companies. Mr. Johnson also stated that ATCO Pipelines (the only gas transmission entity regulated by the Commission) has significantly less risk now than in 2004 due to its proposed integration with NGTL, and if the agreement is implemented, Mr. Johnson states that ATCO Pipelines' risk will be similar to that of NGTL[343] (which is no longer regulated by the Commission but which was considered by the Board to have less risk than ATCO Pipelines in 2004).

368. The UCA stated that the business risk of gas transmission is low-moderate although somewhat elevated since 2004 due to an increase in supply risk. The UCA also submits that the business risk of gas distribution is low to moderate and similar to 2004 with the exception of lower operating leverage risk resulting from the introduction of a weather deferral account for ATCO Gas.[344]

369. Ms. McShane compared the utilities to industry sector-specific benchmarks for ranking purposes.[345] She rates AE Transmission, AE Distribution, and ATCO Gas as all having similar business risk to the industry benchmark. Ms. McShane rates ATCO Pipelines as having higher business risk relative to its sector-specific benchmark.[346]

370. The Commission observes that there is a general consensus on the rank ordering of risk by sector. The electric transmission sector is considered to have the least risk. No party argued otherwise and the Commission agrees.

371. The Commission also finds in general that the electricity distribution segment is slightly more risky than electricity transmission. The Commission agrees with ATCO that ATCO Gas has a similar level of business risk compared to electric distribution companies. The Commission is persuaded that due to its small size, AltaGas is more risky than ATCO Gas. The Commission agrees with ATCO that ATCO Pipelines (transmission) is more risky than ATCO Gas (distribution).

6.7 Company-Specific Considerations

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

6.7.1 Adjustment for Non-taxable Status

373. In Decision 2004-052 the EUB approved a 2 percent increment in the common equity ratio for non-taxable utilities. The Board said, at page 45 of Decision 2004-052:

[342] Exhibit 170.01,UCA-AML-19(c).
[343] Exhibit 180.02 and 180.03, Evidence of Mr. Johnson, pages 2-3.
[344] UCA Argument, Exhibit 387.01, pages 62-64.
[345] Exhibit 50.01, McShane Evidence, Section 4.0, page 15.
[346] Exhibit 50.01, McShane Evidence, Section 4.0, page 3, table 1.

> The Board agrees that a non-taxable entity has a higher volatility of earnings than an otherwise equivalent taxable company, arising from the lack of an income tax component in its forecast revenue requirement. The Board notes that there was no disagreement that the absence of taxation, while lowering costs, increases the volatility of earnings.

374. This issue was discussed by Commissioner Kolesar and Ms. McShane as follows:

> Q So the logic of giving the non tax-paying company an extra 2 percent of equity thickness is because the tax-paying company is actually collecting in its rates the expected income tax. So it kind of gives them that extra layer of buffer so that on an after-tax basis, they would -- or sorry, on a pretax basis, they actually have more cash flow that they could use to pay debt with. That's, I believe, the fundamental logic of why they get that – why the non tax-paying company gets the extra 2 percent because they don't have the benefit of that additional buffer.
> MS. McSHANE: What you say is true, and if I go back to Decision 2004-052, at the time of the decision, we had basically three -- what I'll call three types of utilities: Non taxable, fully taxable and AltaLink, which was semi taxable.[347]

375. ENMAX and EPCOR submitted that they should continue to be awarded an additional 2 percent of equity to account for their status as a non-taxable utility. ENMAX submitted that the EUB's previous decision remains valid today and that an additional 2 percent equity should still be awarded to account for the higher business risks and earnings volatility of a non-taxable entity.[348]

376. The UCA's witnesses Drs. Kryzanowski and Roberts did not support a 2 percent addition of equity thickness for non-taxable utilities. The UCA argued that an adjustment to equity thickness suffers from two major flaws:

> First, it is based on the same overly simplistic view of financial markets that they (Kryzanowski and Roberts) debunked in the earlier discussion of ratio guidelines employed by rating agencies. S&P itself neither states nor acts as if it believed that having a key ratio below a certain target level (due to non-taxable status or other reasons) is grounds for a downgrade. Second, the UCA's witnesses demonstrate that there is a positive side to non-taxable status as it can lead to greater upside when a utility overearns its allowed returns.[349]

377. Drs. Kryzanowski and Roberts also argued that utilities under Alberta's regulatory regime are more likely to over-earn than under-earn. Their Schedule 2.10, Average Actual and Approved Return on Equity for Applicant Utilities 2001–2007, showed that out of five non-taxable utilities three of them over-earned (actual ROE was greater than allowed ROE.).

378. The CCA supports the arguments of the UCA and states in its Reply that it does not support an increase in equity ratio for non-taxable status utilities.[350] The CCA also submitted that there is benefit to the utility from over earning because there are no associated taxes. As a result the non-taxable utility would earn a greater return than a taxable utility when it earns more than its approved rate of return.[351] Calgary also submits in its Argument that an adjustment for

[347] Transcript, page 1872, line 19.
[348] EPC Argument, Exhibit 385.02, page 15.
[349] Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 240, lines 1-24.
[350] CCA Reply Argument, page 14, paragraph 52.
[351] CCA Reply Argument, page 14, paragraph 52.

non-taxable utilities is likely not needed and its witness, Mr. Johnson, went on to question whether the 2 percent adjustment should be changed in light of lower corporate tax rates.[352]

379. Dr. Vander Weide, stated in his evidence that he agreed with an additional 2 percent deemed common equity that the Alberta regulators have been recognizing. Dr. Vander Weide states:

> I agree with the EUB's decision that non-taxable utilities should have higher deemed equity ratios because, other things equal, they have greater variability in net income and return on equity and lower interest coverage ratios than fully taxable utilities.[353]

380. Dr. Vander Weide further states:

> Other things equal, a utility whose revenue requirement does not include an income tax allowance (i.e., a Non-Taxable Utility) has a lower interest coverage ratio, higher variability in operating income, and higher variability in return on equity.[354]

381. Fortis submitted that, due to combined effects of its flow-through tax approach adopted for rate making and its large capital programs, it anticipates being a non-taxable entity until at least 2013.[355] Fortis submits that the rationale applied from Decision 2004-052 for a utility to be considered for non-taxable applies to Fortis and that logic, consistency, and fairness indicate that the 2 percent addition to equity thickness should apply to Fortis in its current situation.[356]

382. The CCA disagrees with granting the two percent increment to Fortis. The CCA submits that Dr. Vander Weide was not asked to provide an opinion on this and considers that Fortis has not provided expert evidence to justify its position on non-taxable status.[357] The CCA stated in Argument that it is alarmed over the use of non taxable status as an argument for increased risk of the utility and a higher equity ratio requirement.

383. The Commission agrees that entities with tax exempt status have a higher volatility of earnings than otherwise equivalent taxable companies because of the absence of an income tax component in their forecast revenue requirements. There was no disagreement among participants in the proceeding that while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios. Therefore, the Commission will continue to add two percentage points to the equity ratios of income tax exempt utilities.

384. The Commission agrees with Fortis that since it is currently non-taxable and expects to be so at least for the near-term future, it too qualifies for the addition of two percentage points to its equity ratio. This status would change if Fortis became an income tax paying entity or if the Commission were to change from the flow through method of accounting for income taxes for revenue requirement purposes to the normalized tax or another similar method in the future.

352 Transcript. page 3658, lines 3-8.
353 Exhibit 56.04, Supplemental Evidence Dr. Vander Weide, pages 2-3.
354 Exhibit 282.01, Reply Evidence Dr. Vander Weide, pages 46-51.
355 Exhibit 53.03, Fortis Evidence, pages 1-2.
356 Fortis Argument, Exhibit 382.03, pages 2-11.
357 CCA Argument, Exhibit 391.01, page 29.

6.7.2 ATCO Gas 2008 Capital Structure

385. ATCO Gas's equity ratio for 2008 remains to be determined in this proceeding. In Argument, ATCO explained how it had filed its evidence as follows:

> ATCO Gas is requesting a common equity ratio of 40% with an ROE of 11.0% for 2009. The same factors which support an increase in AG's common equity ratio for 2009 are applicable to 2008 as discussed in Ms. McShane's evidence attached as Appendix F to the ATCO Utilities' application (wherein a common equity ratio of 40% - at the 2008 formula ROE - is requested).[358]
>
> …..the ATCO Utilities present their own analysis of what a Fair Return for 2009 should be for each utility sector; and what an appropriate capital structure should be for 2008 for ATCO Gas.[359]

386. The UCA stated that it had specifically studied the required equity ratio for ATCO Gas (ATCO Gas and ATCO Pipelines) for 2008.[360] In Argument the UCA stated:

> To ensure fairness across applicant utilities to this proceeding, the UCA recommends that the Commission apply the 2004 Generic Cost of Capital decision to these two utilities. In other words, it would be "consistent to leave it where it is now just for 2008".[361]

387. The Commission has examined ATCO Gas's request to adjust the 2008 equity ratio from 38 percent to 40 percent. The Commission recognizes that the effects of the financial crisis were beginning to be felt during 2008 and that, as a result, some increase in ATCO Gas's equity ratio would have been warranted. Therefore, the Commission allows an equity ratio of 39 percent for ATCO Gas in 2008.

6.7.3 Adjustments for Smaller Utilities

388. During the proceeding AltaGas had observed that due to its small size it was exposed to greater business risk than larger companies which operate in the same sector. In its Evidence, AltaGas stated:

> The AUI evidence in the case does not compare its business risks in 2004 to those experienced today. It reasonably and properly compares the risk of AUI relative to other utilities. As a result of its small size, regulatory risk, service territory (operating) risk and financial market risks, the overall risk of AUI is higher than its larger utility peers, justifying a higher equity component of its capital structure and a higher return.

389. AltaGas also submitted that smaller firms have greater difficulty accessing public debt and, as a result, they often must rely on short-term loans from banks. This makes small firms more sensitive to fluctuations in interest rates than larger companies that can access longer term debt and exposes smaller companies to greater interest-rate risk, and other financial risks.[362] The Commission agrees that AltaGas's small size continues to warrant a higher equity ratio compared to ATCO Gas.

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358 ATCO Argument, Exhibit 390.02, page 98.
359 ATCO Argument, Exhibit 390.02, page 1.
360 Transcript, page 2947.
361 UCA Argument, Exhibit 387.01, page 97.
362 Exhibit 58.02, page 158, lines 11-15.

6.7.4 ATCO Pipelines' System Integration with NGTL

390. In August 2008, ATCO Pipelines entered into a memorandum of agreement for the integration of its system with that of NGTL.[363] During the course of the proceeding, Mr. Jansen stated that definitive agreements had been signed subject to customer and regulatory approval. A number of parties discussed how the agreement might affect the business risks of ATCO Pipelines. Calgary submitted that the agreement reduces ATCO Pipelines' risk significantly because it significantly reduces competition between ATCO Pipelines and NGTL.[364] In light of the agreement, both Dr. Booth and Drs. Kryzanowski and Roberts have made two separate capital structure recommendations for ATCO Pipelines, one with integration (33 and 34 percent respectively) and one without integration (37 and 42 percent respectively).[365]

391. ATCO responded in Reply Argument that it is difficult to ascertain with any degree of confidence what the risk profile of ATCO Pipelines would be post-integration. ATCO went on to say that it is unreasonable to leap to conclusions about the business risk of ATCO Pipelines after integration and that the only thing which is certain is that there will be change.[366]

392. The Commission agrees with ATCO that until the agreement has been finalized and has received regulatory approvals, it is difficult to determine what changes to ATCO Pipelines' risks might occur. Therefore, the Commission will not make adjustments for changes in risk that might result from the agreement. The Commission will re-evaluate business risk following implementation of the agreement.

6.7.5 ATCO Gas 2009 Capital Structure

393. In Decision 2008-113,[367] the Commission approved a weather deferral account for ATCO Gas effective January 1, 2008. In her evidence, Ms. McShane for ATCO concluded that business risk for ATCO Gas had not changed since 2004 because any reduction in risk from a weather deferral account has been offset by other risks. She stated:

> Any reduction in risk due to the proposed weather deferral account is offset by increasing cost recovery risks associated with declining customer usage and a high growth economy.[368]

394. During the proceeding, UCA stated that the weather deferral account approved for ATCO Gas has reduced its level of risk since the last Generic Cost of Capital Proceeding.[369] Drs. Kryzanowski and Roberts rate ATCO Gas's operational risk as low-moderate and also note that it has been reduced by the approval of a weather deferral account.[370]

395. Bond rating agencies also view weather deferral accounts as risk-reducing tools. Drs. Kryzanowski and Roberts referred to a DBRS report as follows:

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363 Exhibit 50.01, Section 4.0, Evidence of Ms. McShane, page 45.
364 Calgary Argument, Exhibit 386.02, page 21.
365 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 6; CAPP Argument, Exhbit 388.02, page 94.
366 ATCO Reply Argument, pages 41-42.
367 Decision 2008-113 - ATCO Gas 2008-2009 General Rate Application Phase I (Application No. 1553052, Proceeding ID. 11) (Released: November 13, 2008).
368 Exhibit 50.02, Appendix F, Capital Structure for ATCO Gas, Kathleen C. McShane, page 3.
369 Exhibit 178.02, Evidence of B. Marcus, page 20.
370 UCA Argument, Exhibit 387.01, page 62.

Writing prior to its approval, DBRS states the rationale for a weather deferral account as a risk-reducing tool:

> The Company's earnings and cash flows, particularly at ATCO Gas where residential customers account for nearly 50% of volume distributed, are sensitive to the weather. Significant changes in weather from one year to the next can impact earnings and cash flows. A 10% change in normal temperatures impacts annual earnings by approximately $10 million. ATCO Gas is seeking approval from the AUC to set up a deferral account mechanism that would, if approved, eliminate the impact of temperature on ATCO Gas earnings.[371]

396. Drs. Kryzanowski and Roberts conclude that this indicates that DBRS would consider ATCO Gas's weather deferral account to reduce its risk.[372]

397. During the proceeding Dr. Vilbert observed that weather risk is not a risk that affects the cost of capital and that only non-diversifiable business risks should be reflected in cost of capital determinations.[373] CAPP's expert Dr. Booth agrees with Dr. Vilbert and stated that weather is the "ultimate" in a completely diversifiable risk.[374]

398. The Commission considers that weather risk is diversifiable for equity investors but is not diversifiable for debt investors. Debt returns to investors are capped at the contracted interest rates and do not benefit from potential unexpected profits (or losses) than can accrue to equity. Therefore, debt investors have lower diversification opportunities. The Commission finds that a weather deferral account does reduce business risk. In the case of ATCO Gas specifically, the Commission agrees that its business risks have been reduced and therefore a reduction in its equity ratio is warranted.

6.7.6 Transmission Facility Owners and Section 42 of the *Transmission Regulation*

399. Transmission facility owners (TFO) are facing an unexpected period of substantial capital investment and have indicated that they need to be in a position to attract capital to finance these large construction projects. AltaLink states in its Argument that:

> With the introduction of the AESO's New 10 Year Transmission Plan and with the introduction of Bill 50 in June of 2009, AltaLink's capital estimates proved to be seriously understated. Under Bill 50, the need for critical transmission infrastructure will be determined by the Province including mandating the need for two HVDC lines between Edmonton and Calgary and two 500 kV lines between Fort McMurray and Edmonton.[375]

400. Ms. McShane as well as Drs. Kryzanowski and Roberts have stated that ATCO Electric's business risk has increased because of the risks associated with the forthcoming large

[371] Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 92, DBRS Rating Report, CU Inc., May 13, 2008, page 3.
[372] Exhibit 179.02, Evidence of Evidence of Drs. Kryzanowski and Roberts, page 92, DBRS Rating Report, CU Inc., May 13, 2008.
[373] AltaGas Argument, Exhibit 384.01, page 25, lines 9-12.
[374] Transcript, pages 3630-3631
[375] AltaLink Argument, Exhibit 389.03, page 2.

construction builds.[376] During the Proceeding parties observed that the provincial government had enacted section 42 of the *Transmission Regulation* to deal with the challenges that might be faced by TFOs building large transmission projects to support Alberta's competitive electricity generation market. Section 42 states:

> In addition to the matters taken into account by the Commission under section 122 of the [Electric Utilities] Act, when considering an application for approval of a TFO tariff, the Commission must consider that it is also in the public interest to provide consumers the benefit of unconstrained transmission access to the competitive generation market
>
> (a) by providing sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and
>
> (b) by fostering a stable investment climate and a continued stream of capital investment for the transmission system.

401. During the Proceeding, the Commission heard varying perspectives of the interpretation of section 42 of the *Transmission Regulation* and the relationship between section 42 and section 122 of the *Electric Utilities Act*.

402. AltaLink argued that section 42 of the *Transmission Regulation* is to be considered as providing financial assurances in addition to section 122. In its Argument AltaLink stated:

> Section 42 is **in addition to the matters** to be taken into account by the Commission under section 122. Therefore, on its face, section 42 of the Transmission Regulation is not simply duplicative of section 122 of the *Electric Utilities Act*.[377]

403. Mr. Weismiller, company witness for ENMAX, stated at the hearing that his understanding of section 42 was that it did not add much in relation to section 122.[378] EPCOR and ATCO both stated at the hearing that as long as the applicant utility was consistently awarded a fair return then it would be able to go out and raise capital at anytime and if a fair return was awarded then no additional consideration would be required by the Commission in terms of return, increase in ROE or increase in capital structure.[379] In response to a question from Commission Counsel at the hearing, Mr. Stout of EPCOR stated:

> …and now I will get back to Section 42, which I see there is really as a reminder to the regulator and a reminder to the companies that the regulatory compact still exists, that we've gone through a cycle in transmission building of little investment, even of neglect, if you like, to one where we need to do a lot of catch-up investment and strengthen that transmission system, and it now becomes critically important that the TFOs are able to finance and gather the capital necessary to build that. But I don't see it as anything more than that. I don't see it as suggesting there should be some extra juice or extra favour in terms of return on equity or anything else. I think it simply is an underscoring of, hey, there's a regulatory compact here in times of slowdown and in times of rapid growth."[380]

[376] ATCO Argument, Exhibit 390.02, page 94.
[377] AltaLink Argument, Exhibit 389.03, page 26, paragraph 59.
[378] Transcript, page 2603, line 25 to page 2604, line 2.
[379] Transcript, page 471, line 22 to page 472, line 19 and page 1790, lines 11-25.
[380] Transcript, page 471, line 22 to page 472, line 11.

404. The Commission does not interpret section 42 of the *Transmission Regulation* to require it to provide TFOs with additional returns. Rather, it is meant to provide authorization to the Commission to consider a wide range of regulatory mechanisms that could assist the TFOs in financing their transmission builds. A number of options, including an increased allowed ROE, a higher equity ratio and the inclusion of construction work in progress (CWIP) in rate base are available to TFOs to assist in the transmission builds.

405. Ms. Abbott (appearing for AltaLink as a former credit analyst) was of the opinion that the ability to include CWIP in rate base would be viewed as a positive by the credit rating agencies.[381] CWIP for a regulated utility provides an opportunity to capitalize, through an Allowance for Funds Used during Construction (AFUDC), the interest and ROE on the utility's investment in CWIP. In this manner the utility receives a non-cash return through AFUDC. The AFUDC is added to rate base and the utility receives its cash return on this cost of financing its CWIP over the life of the constructed assets.

406. Where immediate cash flow is more important to the utility than the opportunity to add to rate base through AFUDC on CWIP, the ability to put CWIP in rate base would be beneficial to a utility because it advances the non-cash AFUDC associated with the assets under construction to current cash flows for the utility. This in turn lowers the risk of the utility.

407. Counsel for AltaLink, in final Argument, stated that:

> AltaLink appreciates the Commission's interest in exploring novel approaches to addressing the cash flow issues caused by significant transmission expansion. While CWIP in Rate Base has some merit and provides some improvements in cash flow, it is not a substitute for fair return. It is AltaLink's view that more must be undertaken to fully understand CWIP in rate base.[382]

408. Accordingly, the Commission will defer any decision about inclusion of CWIP in rate base until such time as an application is made to it by a TFO. This approach is consistent with the Commission's approach in the recent AltaLink Management Ltd. TFO Tariffs decision.[383] In that decision, the Commission approved AltaLink's proposal to continue to utilize the Future Income Tax (FIT) method. Neither a 38 percent equity ratio as a placeholder nor a CWIP in rate base solution to AltaLink's credit rating concerns was awarded. The Commission stated:

> If, after the effects of the Commission's decision in the GCOC proceeding have been assessed, further measures are required to obviate the potential for a downgrade of AltaLink's credit rating, the Commission is prepared to consider the adoption of measures such as the suspension of normal CWIP accounting procedures on AltaLink's large anticipated capital program. This is the Commission's preferred method of addressing any remaining credit metric concerns identified by AltaLink in the Application because it directly addresses the fundamental cause of the cash flow problem that is impacting credit metrics.[384]

[381] Transcript, pages 396-397.
[382] AltaLink Argument, Exhibit 389.03, paragraph 70.
[383] Decision 2009-151 – AltaLink Management Ltd. and TransAlta Corporation 2009-2010 Transmission Facility Owner Tariffs, (Released October 2, 2009), paragraph 563.
[384] Decision 2009-151, paragraph 617.

409. The Commission concludes, as stated above, that it does not interpret section 42 of the *Transmission Regulation* to require it to provide TFOs with additional returns and the Commission will defer any decision to consider regulatory mechanisms that could assist the TFOs in financing their transmission builds to such time when an application is made by a TFO.

6.8 Conclusion Regarding Required Capital Structures

410. The Commission has examined a number of factors that are relevant to determining required equity ratios. These include a consideration of the impacts of the financial crisis, the ranking of the utility segments based on business risk, the levels of key credit metrics that are associated with the actual credit ratings of relatively pure-play Canadian utilities, and the levels of equity ratios that are associated with the actual credit ratings of relatively pure-play Canadian utilities. Two factors that particularly impacted the electric transmission sector were also examined; the impact of CWIP and the impact of the Transmission Regulation. Finally, three factors specific to certain individual utilities were examined; the non-taxable status of a number of the utilities, the small size of AltaGas, and the competitive situation facing ATCO Pipelines.

411. Accordingly, the Commission makes the following findings:

1. The credit crisis warrants an increase in the equity ratios for all utilities to reflect increased risk and the re-pricing of risk.
2. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta Utilities should be 34 percent based on EBIT analysis, (which is 1 percentage point higher than the existing level awarded to transmission companies), 30 to 36 percent based on FFO/Debt analysis and 33 percent based on FFO interest coverage analysis; (ii) as a result of lower income tax rates and lower ROEs a 4 percentage point equity ratio increase would be required to maintain credit metrics at the same level as the 2004 levels; and (iii) the 4 percentage points equity ratio increase would be offset to some degree by the lower debt costs in 2009 versus 2004.
3. The analysis of the equity ratios of relatively pure play Canadian utilities and their actual credit ratings does not indicate that any equity ratio increase is required.
4. The business risk analysis does not indicate that there have been major changes in the relative risks of the various utilities segments. Hence, any increase in equity ratios should be relatively uniform across the sectors and individual utilities unless utility-specific considerations require otherwise.

412. After considering all of the above the Commission awards a 2 percentage point base increase in the equity ratios of the Alberta utilities. Company specific adjustments to this base increase are as follows:

AltaLink, ATCO Electric and TransAlta

These electric transmission utilities are awarded a 3 percentage point increase to their equity ratios. This consists of the 2 percentage point base increase discussed above plus an additional 1 percentage point increase in recognition of the impacts of the large capital additions forecast by these utilities and the resulting negative impacts on their credit metrics.

ATCO Gas

In respect of 2008, ATCO Gas is awarded a 1 percentage point increase in its equity ratio. For 2009, it is awarded a 1 percent increase. This is based on the 2 percentage point base increase and a deduction of 1 percentage point to recognize that it now has a weather deferral account.

FortisAlberta

As determined in section 6.7.1, FortisAlberta is awarded an additional 2 percentage points in its equity ratio since it is currently non-taxable.

Table 17. Equity Ratio Findings

	Last Approved (%)	Requested (%)	2009 (%)
Electric and Gas Transmission			
ATCO Electric TFO	33	38	36
AltaLink	33	38	36
ENMAX TFO	35	40	37
EPCOR TFO	35	40	37
RED Deer TFO	35	n.a.	37
Lethbridge TFO	35	n.a.	37
TransAlta	33	n.a.	36
ATCO Pipelines	43	43	45
Electric and Gas Distribution			
ATCO Electric DISCO	37	40	39
ENMAX DISCO	39	44	41
EPCOR DISCO	39	44	41
ATCO Gas	38	40	39
ATCO Gas for 2008	38	40	39
FortisAlberta	37	44	41
AltaGas	41	46	43
Retailers			
EEAI	37	42	39

6.9 Future Adjustments to Capital Structure

413. The equity ratios awarded in this Proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

7 ADJUSTMENT FORMULA

414. Having determined the fair generic rate of return on equity for 2009, the Commission must consider how that rate of return might be adjusted in future years. One of the principal purposes of this proceeding has been to consider whether the annual adjustment formula adopted by the EUB in 2004 should be retained, and if not, whether a new formula for annual adjustments to ROE or any formula at all should be adopted by the Commission.

415. The utilities appearing at the hearing unanimously asserted that the 2004 formula is broken. Some utilities argued that the formula no longer produces a fair ROE because

circumstances in the capital markets have changed. The utilities submitted that the traditional expectation that corporate bond rates and market equity returns would decline as the Bank of Canada interest rate and 30 year Government of Canada bond rates declined is no longer the reality.[385] Therefore, since the formula was based on the expectation that that relationship would continue and it did not, the formula has calculated a lower rate of return than is required in 2009. Other utilities argued that the formula never[386] has produced a fair ROE because it relies too heavily on one factor (the level and movement of the 30-year Government of Canada bond rate) and does not consider other factors such as earnings of comparable utilities. In particular, it does not take into account the high rates of return and higher equity thickness generally awarded by United States utility regulators.

416. The interveners unanimously asserted that the formula is not broken. It does not produce too low a rate of return. They say that there is no evidence that the utilities have been unable to raise capital or that their financial integrity has been impaired. Indeed, they argue that evidence of stand-alone Canadian utilities being sold at market to book ratios above one demonstrates that the formula may even have produced too high a rate of return.[387] Finally, they argue that United States regulatory awarded returns are not relevant because the circumstances under which the U.S. utilities operate result in higher risk for those utilities.

417. In this Decision, the Commission has undertaken an assessment of the generic rate of return on equity independently of the 2004 formula in order to establish a fair rate of return on equity for Alberta utilities in 2009 of 9.0 percent. The 2004 formula was developed based on the expectation that the rate of return it produced would move in the same direction as the return of the 30-year Government of Canada bond. If the movement in the bond return is not similar to the movement in the market return then at times the allowed return may be overstated or understated. The Commission accepts that the traditional relationships between Government of Canada 30-year bond rates and market equity returns did not continue through the entire period 2004 to the present. The Commission notes that between July 2008 and March 2009 the long Canada bonds rate declined more than 40 basis points.[388] The Toronto Stock Exchange halved in value and the required market equity rate of return appears to have increased at the same time. Because of the way the formula had been designed, it was not capable of adjusting for the unexpected changes in the relationships that occurred in the capital markets, as a result of the financial crisis. The formula produced results for 2009 that were not correlated with the market movements. The allowed return for 2009 that the formula would have produced was 8.61 percent.

418. At the hearing, interveners argued that financial markets are healing[389] and that the historical relationships reflected in the formula were quickly returning. However the Commission observes that after the low in the stock market was reached in March 2009, the Toronto Stock Exchange recovered nearly half of its losses[390] at the same time as the yield on long Canada bonds increased by over 50 basis points.[391] Directionally, long Canada bonds

385 Written Evidence of AltaLink Management Ltd., Exhibit 57.03, Figure 1.2a and pages 9-10.
386 ATCO Argument, Exhibit 390.02, pages 4-5 and Evidence of Dr. Coyne Figure 1, Exhibit 50.01, Section 3.0, pages 4-4
387 Calgary Argument, Exhibit 386.02, pages 17-18 and UCA Argument, Exhibit 387.01, page 86.
388 Exhibit 367.03.
389 CAPP Argument, Exhibit 388.02, page 51.
390 Exhibit 310.
391 Exhibit 367.03.

continued to move in an opposite direction from the required equity market return before and after the March 2009 peak of the crisis. By the end of the hearing in mid 2009, the spread between Government of Canada 30-year bond rates and the corporate bond rate had begun to narrow once again and market equity rates had also begun to decline.[392] There was no evidence to suggest that historical relationships required for the formula to properly reflect utility required returns on equity had been re-established as of the close of the record. Indeed there was still considerable uncertainty in the market. Therefore, the Commission rejects interveners' assertions that it should assume that things are quickly returning to "normal"[393] and that the formula can simply be continued.

419. During the hearing, the Commission explored the possibility of making some adjustments to the 2004 formula in order to recognize the types of changes that had occurred and were occurring in the capital markets. For the most part, the interveners preferred that a formula be retained. The utilities, on the other hand, stated generally that they preferred that no formula be adopted but did engage in discussions about possible changes to the existing formula. A number of possible changes to the formula were suggested but there were still concerns raised that no formula can adequately anticipate all of the changes in capital markets and other factors that might occur to influence the cost of equity. Some of the possible approaches included: adding new review trigger points,[394] resetting the start point,[395] lowering the sensitivity to changes in interest rates[396] and or creating a new ROE adjustment mechanism, indexed to ROE awards for an appropriate group of comparable utilities, bond yields, or a combination of the two.[397]

420. The Commission is unwilling to make any of the suggested changes to the formula at this time because the changes suggested were not and could not have been fully considered during the proceeding while the economic crisis was ongoing and the relationships among various market indicators were fluid. Changing the formula to incorporate the corporate bond rate, while a seemingly simple adjustment, may not be a satisfactory longer term adjustment to the Alberta formula because of perceived concerns about the influence that Alberta's investor-owned utility companies could have on the posted corporate bond rate.[398] Placing a lower limit on the return on equity that could be allowed by a revised formula at this time would not necessarily ensure fairness.

421. At this time, the Commission agrees with Mr. Stout's observations, on behalf of EPCOR, about the use of a formula:

> …we have reservations about the ability of a single formula to accommodate all the conditions. We have similar concerns, by the way, about a single trigger mechanism which also may not necessarily capture all the conditions. We just think the whole issue of what is a fair return and capital structure in the context of very dynamic and volatile markets is something that's very difficult to model and we don't think we're clever enough, let's put it that way, to establish a formula or a trigger mechanism that we think would necessarily produce the right results in all circumstances. So it gives us a certain reservation about formula approaches, if you can appreciate that.

392 Exhibit 310.
393 Transcript, page 3274, line 20.
394 AltaLink Argument, Exhibit 389.03, page 36.
395 ATCO Argument, Exhibit 390.02, page 61 and AltaLink Argument, Exhibit 389.03, page 36.
396 ATCO Argument, Exhibit 390.02, page 61.
397 ATCO Argument, Exhibit 390.02, pages 61-63.
398 Transcript, page 1081 and pages 1083-1084.

422. Nevertheless, because of the number of utility companies regulated by the Commission and the frequency with which they appear before the Commission for revenue requirements, the Commission is not prepared to preclude a return to some sort of formula-based adjustment mechanism in the future when relationships in the capital markets have stabilized and are once again considered reasonably predictable. Dr. Booth suggested that the Commission could consider suspending the formula for a one-year period until a return to normal capital markets[399] and observed that such a return was already occurring during the hearing. However, the Commission is not prepared to simply re-impose the same formula or any formula without a careful assessment of changes in the capital markets and a reconsideration of the types of factors that should be built into a formula.

423. The Commission will not employ an adjustment formula for 2010. As explained above, the Commission has determined that a fair generic rate of return on equity for Alberta utilities for 2009 is 9.0 percent. Some parties suggested that the Commission could also establish a generic rate of return on equity for 2010.[400] Mr. Stout, on behalf of EPCOR also stated "[i]n all probability, what is determined is fair in the latter part of 2009 will probably, as far as we know, be still fair in 2010."[401] Being mindful of the date of the close of the record and based on the record of this proceeding, the Commission concludes that an ROE of 9.0 percent is fair for both 2009 and 2010. This decision to establish an allowed ROE for 2010 is consistent with the desire of investment community for a supportive, transparent and predictable regulatory environment.

424. In order to allow the capital markets some time to return to traditional relationships or show evidence of what the new relationships may be, the Commission orders that the generic ROE for 2011 also be established at the same 9.0 percent on an interim basis subject to change following a proceeding to be initiated in 2011.

8 CONCLUSION AND ORDER

425. The Commission has considered and weighed all of the evidence and argument on the record in determining a fair return on equity capital for participating utilities. The Commission has acted in accordance with its statutory responsibilities and has been guided in the exercise of its judgment by the fair return standard established by the courts. In the Commission's judgment, the total return resulting from the application of a generic ROE of 9.0 percent to the respective equity ratios set out in Table 17 results in a fair return on equity capital for each of the participating utilities for each of 2009 and 2010.

426. For greater certainty, the Commission notes that this Decision does not over-ride the terms of any negotiated settlement approved by the Commission or the terms of any other Commission Order which has established, on a final basis, the 2009 ROE or capital structure for a utility. In the event an approved negotiated settlement is not explicit regarding the final nature of the 2009 ROE or capital structure, parties may make application to the Commission as required.

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399 Transcript, pages 3275-3276.
400 Transcript, pages 209 and 210.
401 Transcript, page 494.

427. IT IS HEREBY ORDERED THAT:

(1) The Generic ROE for 2009 and 2010 is set at 9.0 percent.

(2) The Generic ROE for 2011 is set at 9.0 percent on an interim basis.

(3) Utility equity ratios for 2009, 2010 and until further changed by the Commission, are as set out in the table below.

(4) The equity ratio for ATCO Gas for 2008 is set at 39 percent.

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

Segment	Awarded Equity Ratios (%)
Electric and Gas Transmission	
ATCO Electric TFO	36
AltaLink	36
ENMAX TFO	37
EPCOR TFO	37
RED Deer TFO	37
Lethbridge TFO	37
TransAlta	36
ATCO Pipelines	45
Electric and Gas Distribution	
ATCO Electric DISCO	39
ENMAX DISCO	41
EPCOR DISCO	41
ATCO Gas	39
FortisAlberta	41
AltaGas	43
Retailers	
EEAI	39

Dated in Calgary, Alberta on November 12, 2009.

ALBERTA UTILITIES COMMISSION

(original signed by)

Willie Grieve
Chair

(original signed by)

Tudor Beattie, Q.C.
Commissioner

(original signed by)

Bill Lyttle
Commissioner

(original signed by)

Mark Kolesar
Commissioner

(original signed by)

Anne Michaud
Commissioner

APPENDIX 1 – PROCEEDING PARTICIPANTS

(return to text)

Name of Organization (Abbreviation) Counsel or Representative
AltaLink Management Ltd. (AltaLink) H. Williamson A. Ross
ATCO Gas, ATCO Electric Ltd. and ATCO Pipelines (ATCO Utilities) L. Smith, Q.C.
AltaGas Utilities Inc. (AltaGas) C. K. Yates
BP Canada Energy Company C. Worth
The City of Calgary (Calgary) H. Johnson
Canadian Association of Petroleum Producers (CAPP) L. Manning
Consumers Coalition of Alberta (CCA) J. A. Wachowich
ConocoPhillips Canada Limited J. Gilholme
EPCOR Distribution & Transmission Inc. (EPCOR) J. Liteplo
EPCOR Energy Alberta Inc. (EEAI) J. Liteplo
EnCana Corporation K. Hadley R. Powell
ENMAX Power Corporation (ENMAX) G. Weismiller
FortisAlberta Inc. (Fortis) T. Dalgleish
Industrial Gas Consumers Association of Alberta G. Sproule

Name of Organization (Abbreviation) Counsel or Representative
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City of Lethbridge M. Turner
Nexen Marketing D. White
NOVA Gas Transmission Ltd. (ngtl) A. Harris
The City of Red Deer M. Turner
Shell Canada Energy R. Gall
Shell Energy North America (Canada) Inc. T. Lange
Terasen Gas Inc. T. Loski
Office of the Utilities Consumer Advocate (UCA) R. McCreary
Westcoast Energy Inc. M. Thorp
Cities of Red Deer and Lethbridge M. Turner

APPENDIX 2 – ORAL HEARING – REGISTERED APPEARANCES

(return to text)

Name of Organization (Abbreviation) Counsel or Representative	Witnesses
AltaLink Management Ltd. (AltaLink) H. Williamson Q.C. R. Block, Q.C.	D. Frehlich J. Bronneberg S. D. Abbott J. Vander Weide
ATCO Gas, ATCO Electric Ltd. and ATCO Pipelines (ATCO Utilities) L. Smith, Q.C. K. Beattie	A. Engen O. Edmondson J. Coyne S. Gaske D. DeChamplain K. McShane B. Bale E. Jansen
AltaGas Utilities Inc. (AltaGas) C. Yates, Q.C. D. Langen	E. Tuele A. Mantei P. Newson J. Fan M. Vilbert
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Canadian Association of Petroleum Producers (CAPP) L. Manning N. Schultz	A. Safir L. Booth R. Fairbairn
Consumers' Coalition of Alberta (CCA) J. Wachowich	
EPCOR EPCOR Distribution & Transmission Inc. (EDTI) EPCOR Energy Alberta Inc. (EEAI) J. Lowe	D. Gerke P. Chung R. Stout J. Vander Weide
EnCana Corporation K. Hadley R. Powell	
ENMAX Power Corporation (ENMAX) D. Wood M. Synnott	J. Neri G. Weismiller

Name of Organization (Abbreviation) Counsel or Representative	Witnesses
FortisAlberta Inc. (Fortis) T. Dalgleish, Q.C.	I. Lorimer M. Olson J. Vander Weide
Industrial Power Consumers and Cogenerators Association (IPCCA) M. Forster	
Office of the Utilities Consumer Advocate (UCA) N. Parker T. Shipley	L. Kryzanowski G. Roberts W. Marcus

Alberta Utilities Commission

Commission Panel
- W. Grieve, Chair
- T. Beattie, Q.C., Commissioner
- B. Lyttle, Commissioner
- M. Kolesar, Commissioner
- A. Michaud, Commissioner

Commission Staff
- B. McNulty (Commission Counsel)
- S. Allen
- B. Ploof
- P. Howard
- J. Thygesen
- S. Karim

SEC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/1/2, p. 2

Please provide details of all changes to business risks that the Applicant and/or its experts Concentric believe have arisen a) in the period 1993 to 2007, and b) in the period 2007 to date.

RESPONSE

EGD and Concentric believe that business risks have increased since 1993 to 2011. EGD and Concentric do not believe it is necessary to differentiate risk growth between the two time periods 1993 to 2007 and 2007 to date. Rather, what is necessary is to determine whether the deemed equity ratio is properly situated as a result of changes in business risk over the entire time period. The changes to business risk can be found in the evidence at Exhibit E2, Tab 1, Schedule 2, and Exhibit E2, Tab 2, Schedule 1.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #3

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/1/2, p.7

Please confirm that the Applicant believes the GEA is intended to decrease reliance on natural gas.

RESPONSE

According to the Ontario Ministry of Energy website, “Ontario’s Green Energy Act (GEA) was created to expand renewable energy generation, encourage energy conservation and promote the creation of clean energy jobs.”

Witnesses: R. Fischer
M. Lister
D. Yaworsky

SEC INTERROGATORY #4

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/1/2, p. 14

Please have the Applicant's experts Concentric provide a table showing their estimate of the percentage probability of a downgrade by the rating agencies if the equity thickness remains at 36%, i.e. x% probability of a one-notch downgrade, y% of a two-notch downgrade, etc.

RESPONSE

Concentric has not independently conducted an analysis of the percentage probabilities of a downgrade for any particular ratings grade; however, ratings agencies do typically publish such statistics. For example, according to S&P's recent study of ratings defaults and transitions, the average probability of a one notch downgrade, assuming EGDI's equity thickness remains at 36% and its credit rating of A-, within one year to a BBB+ credit rating is 7.55%; the average probability of a two-notch downgrade within one year to a BBB rating is 2.39%, the average probability of a full rating downgrade within one year to BBB- is 0.73%, and the probability of being downgraded within the next year to below investment grade is 0.20%.[1] These percentages increase substantially as the time horizon increases. For example, in the S&P study, the corresponding probabilities essentially double by adding two years to the time horizon, i.e. the chance of being downgraded by one notch in 3 years becomes 15.13%; the likelihood of a two-notch downgrade becomes 6.49%; the likelihood of a full ratings downgrade to BBB- becomes 2.38%; and a downgrade below investment grade to BB+ becomes 0.58%.[2] The Study

[1] 2011 Annual Global Corporate Default Study And Rating Transitions, Publication date: 21-Mar-2012 09:24:38 EST, See Table 23.
[2] Ibid. See Table 62.

Witnesses: J. Coyne
J. Lieberman
Concentric

can be found attached. The statistics suggest that the probability of a downgrade is not remote and becomes more likely as time goes on.

Witnesses: J. Coyne
J. Lieberman
Concentric

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue E2
Schedule 14.4
Attachment

2011 Annual Global Corporate Default Study And Rating Transitions

Publication date: 21-Mar-2012 09:24:38 EST

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Despite fewer financial and economic headlines than in the past four years, 2011 was still a year of unprecedented events in global credit markets, marked by sovereign downgrades, most notably the U.S. In 2011, 53 global corporate issuers defaulted, down from 81 defaults in 2010 and the record high of 265 in 2009 (see table 1). One of the 53 defaulters began the year rated investment grade (MF Global Holdings Ltd.). The debt amount affected by these defaults fell to $84.2 billion, from $95.7 billion in 2010.

Overall credit stability deteriorated slightly in 2011 (see table 6). Both upgrades and downgrades increased relative to 2010, as did the proportion of withdrawn ratings. In addition, the average number of notches recorded among downgrades fell in 2011 to 1.4 versus 1.52 the previous year (see chart 13).

All but one of the defaulted companies in 2011 that began the year with active ratings (44) came from the speculative-grade universe (see table 1). Of the remaining nine, Standard & Poor's Ratings Services assigned ratings on five companies during 2011, and four began the year with withdrawn ratings. Also, of the 53 total defaulters, 47 were initially rated speculative grade, with the majority (39) from the 'B' and 'CCC'/'C' rating categories.

At the end of December 2011, the speculative-grade default rates fell to 1.98% in the U.S., 0.59% in the emerging markets, and 5.98% in an assorted grouping of other developed markets (including Australia, Canada, Japan, and New Zealand). In Europe, however, the default rate rose slightly at year-end 2011, to 1.6% (see table 7). When including all rated entities, the global default rate declined to 0.75% in 2011 from 1.15% a year earlier.

This study includes industrials, utilities, financial institutions (which includes banks, brokerages, asset managers, and other financial entities), and insurance companies around the world with long-term local-currency ratings. All default rates reported are calculated on an issuer-weighted basis. For a detailed explanation of the data sources and methodology used in the study, please refer to Appendix I.

Although the incidence of default fell for the second year in a row following the height of the credit crisis in 2009, the one-year Gini ratio--a key measure of the relative ability of ratings to differentiate risk--declined slightly, to 88.7% in 2011 from 90.1% in 2010. One of the main contributors to the recent decline was the default of MF Global Holdings Ltd., which began the year rated 'BBB-'. Despite the drop in the Gini ratio, it's still at its sixth-highest level in the 31-year history of the database (see chart 30) and is higher than the one-year average of 84.2% (see table 2). (For details on the Gini methodology, refer to Appendix III.) Further testifying to the relative decline in default activity in 2011, transportation was the only sector that recorded an annual default rate in excess of its long-term weighted average (see chart 2). The default rates in this study that we refer to as weighted averages use the number of issuers at the beginning of each year as the basis for each year's weight. When broken out by rating, every rating category had an annual default rate in 2011 that was below its long-term average (see table 9).

Table 1

Global Corporate Default Summary

Year	Total defaults*	Investment-grade defaults	Speculative-grade defaults	Default rate (%)	Investment-grade default rate (%)	Speculative-grade default rate (%)	Total debt outstanding (bil. $)
1981	2	0	2	0.14	0.00	0.62	0.06
1982	18	2	15	1.19	0.18	4.41	0.90
1983	12	1	10	0.76	0.09	2.93	0.37
1984	14	2	12	0.91	0.17	3.26	0.36
1985	19	0	18	1.11	0.00	4.31	0.31
1986	34	2	30	1.72	0.15	5.66	0.46
1987	19	0	19	0.95	0.00	2.79	1.60
1988	32	0	29	1.39	0.00	3.84	3.30
1989	43	2	35	1.74	0.14	4.66	7.28
1990	70	2	56	2.74	0.14	8.09	21.15
1991	93	2	65	3.27	0.14	11.04	23.65
1992	39	0	32	1.50	0.00	6.08	5.40
1993	26	0	14	0.60	0.00	2.50	2.38
1994	21	1	15	0.62	0.05	2.10	2.30
1995	35	1	29	1.04	0.05	3.52	8.97
1996	20	0	16	0.51	0.00	1.80	2.65
1997	23	2	20	0.63	0.08	2.00	4.93

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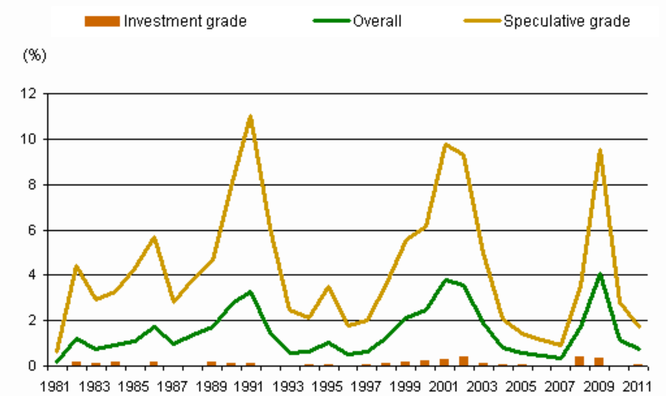
1998	56	4	48	1.27	0.14	3.65	11.27
1999	109	5	92	2.13	0.17	5.55	39.38
2000	136	7	109	2.45	0.24	6.14	43.28
2001	229	8	173	3.77	0.26	9.74	118.79
2002	225	13	158	3.54	0.41	9.32	190.92
2003	120	3	89	1.90	0.10	4.98	62.89
2004	56	1	39	0.79	0.03	2.05	20.66
2005	39	1	30	0.58	0.03	1.44	42.00
2006	29	0	25	0.45	0.00	1.13	7.13
2007	24	0	21	0.37	0.00	0.89	8.15
2008	126	14	88	1.74	0.41	3.56	429.63
2009	265	11	223	4.06	0.32	9.52	627.70
2010	81	0	63	1.15	0.00	2.82	97.48
2011	53	1	43	0.75	0.03	1.71	84.26

*This column includes companies that were no longer rated one year prior to default. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 1

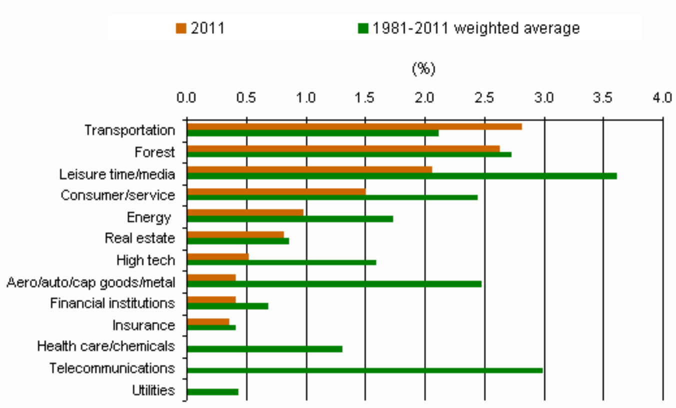
Global Default Rates: Investment Grade Versus Speculative Grade



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 2

Global Corporate Default Rates By Industry: 2011 Versus Long-Term Average



High tech--High technology/computers/office equipment. Forest--Forest and building products/homebuilders. Energy--Energy and natural resources. Aero/auto/cap goods/metal--Aerospace/automotive/capital goods/metal. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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The Gini ratios are a measure of the rank-ordering power of ratings over a given time horizon--i.e., one through seven years (see chart 3). It shows the ratio of actual rank-ordering performance to theoretically perfect rank ordering.

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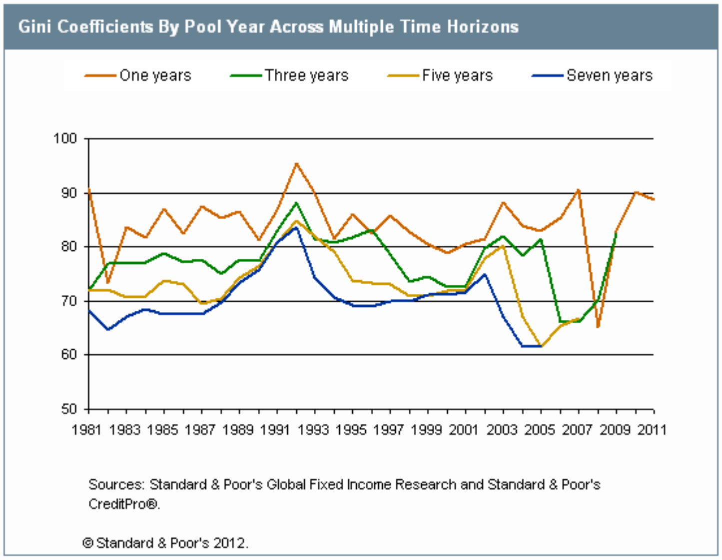
Chart 3



All of Standard & Poor's default studies have found a clear correlation between ratings and defaults: The higher the rating, the lower the observed frequency of default, and vice versa. Over each time span, lower ratings correspond to higher default rates (see chart 4 and chart 25). We found that the same is true when we broke out the data by rating (see tables 24 and 26), as well as by region (see table 25). As the Gini ratios show, the ability of corporate ratings to serve as an effective measure of relative risk remains intact, particularly in low-default years. Many default studies, including this one, also look at transition rates, which gauge the degree to which ratings change--either up or down--over a particular time. Transition studies have repeatedly confirmed that higher ratings tend to be more stable and that speculative-grade ratings generally experience more volatility. However, with the downgrade of the U.S. (AA+/Negative/A-1+) and other sovereigns in 2011, many corporations--particularly in the financial sector--with ratings tied to the countries they operate in experienced subsequent downgrades. This decreased the relative stability of rating categories with smaller sample sizes, such as 'AAA'.

Table 2

Global Average Gini Coefficients By Broad Sector (1981-2011)

	--Time horizon--			
Sector	One year	Three years	Five years	Seven years
Global				
Weighted average	82.05	75.47	71.58	69.81
Average	84.17	77.35	73.13	70.26
Standard deviation	(5.59)	(5.04)	(5.24)	(5.03)
Financial				
Weighted average	77.75	66.48	59.75	57.69
Average	82.79	71.06	63.50	59.38
Standard deviation	(16.90)	(14.51)	(15.64)	(13.66)
Nonfinancial				
Weighted average	80.97	74.19	70.17	68.28
Average	83.56	76.53	72.38	69.45
Standard deviation	(6.49)	(5.53)	(5.50)	(5.20)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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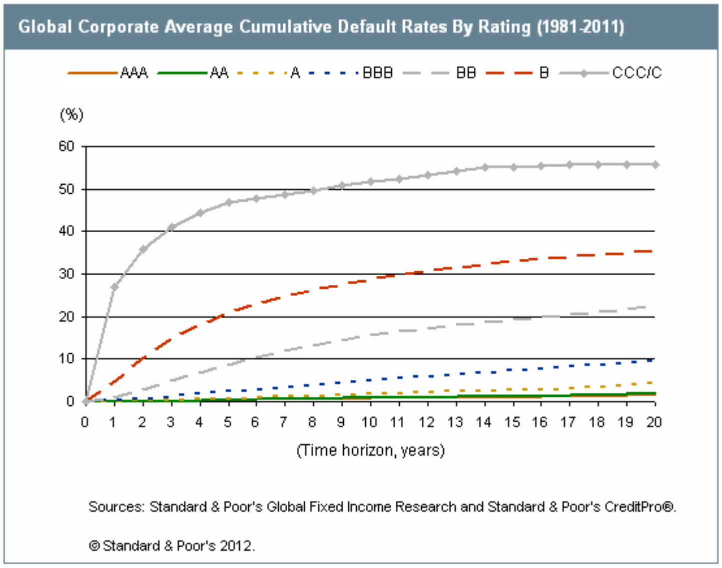
Chart 4



With the exception of MF Global, all of the defaulters in 2011 began the year rated in the lowest rating categories--particularly 'B' and 'CCC'/'C' (see table 3). One-year default rates are now close to levels not seen since prior to the financial crisis that began in late 2007, while all rating categories finished 2011 with one-year default rates well below their long-term weighted averages (see table 4). This was especially the case among the lowest-rated companies. Once again, the default rate in the 'AAA' rating category was zero, demonstrating that the default record for corporate ratings in this category remained unblemished and consistent with historical trends.

Table 3

Global Corporate Annual Default Rates By Rating Category

(%)	AAA	AA	A	BBB	BB	B	CCC/C
1981	0.00	0.00	0.00	0.00	0.00	2.27	0.00
1982	0.00	0.00	0.21	0.34	4.22	3.13	21.43
1983	0.00	0.00	0.00	0.32	1.16	4.55	6.67
1984	0.00	0.00	0.00	0.66	1.14	3.39	25.00
1985	0.00	0.00	0.00	0.00	1.48	6.44	15.38
1986	0.00	0.00	0.18	0.33	1.31	8.33	23.08
1987	0.00	0.00	0.00	0.00	0.37	3.08	12.28
1988	0.00	0.00	0.00	0.00	1.04	3.62	20.37
1989	0.00	0.00	0.00	0.60	0.72	3.37	33.33
1990	0.00	0.00	0.00	0.58	3.56	8.54	31.25
1991	0.00	0.00	0.00	0.55	1.68	13.84	33.87
1992	0.00	0.00	0.00	0.00	0.00	6.99	30.19
1993	0.00	0.00	0.00	0.00	0.70	2.62	13.33
1994	0.00	0.00	0.14	0.00	0.27	3.08	16.67
1995	0.00	0.00	0.00	0.17	0.99	4.58	28.00
1996	0.00	0.00	0.00	0.00	0.67	2.90	4.17
1997	0.00	0.00	0.00	0.25	0.19	3.49	12.00
1998	0.00	0.00	0.00	0.41	0.81	4.61	42.86
1999	0.00	0.17	0.18	0.19	0.95	7.29	33.33
2000	0.00	0.00	0.26	0.37	1.26	7.83	34.12
2001	0.00	0.00	0.35	0.33	3.14	11.24	45.87
2002	0.00	0.00	0.00	1.02	2.84	8.11	44.64
2003	0.00	0.00	0.00	0.23	0.57	4.02	33.13
2004	0.00	0.00	0.08	0.00	0.53	1.56	15.56
2005	0.00	0.00	0.00	0.07	0.20	1.73	9.02
2006	0.00	0.00	0.00	0.00	0.30	0.81	12.38
2007	0.00	0.00	0.00	0.00	0.19	0.25	14.95
2008	0.00	0.38	0.38	0.48	0.78	4.00	26.00
2009	0.00	0.00	0.22	0.54	0.73	10.43	48.68
2010	0.00	0.00	0.00	0.00	0.55	0.81	22.07
2011	0.00	0.00	0.00	0.07	0.00	1.50	15.94

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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Table 4

Descriptive Statistics On One-Year Global Default Rates

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	AAA	AA	A	BBB	BB	B	CCC/C
Minimum (%)	0.00	0.00	0.00	0.00	0.00	0.25	0.00
Maximum (%)	0.00	0.38	0.38	1.02	4.22	13.84	48.68
Weighted long-term average (%)	0.00	0.02	0.08	0.24	0.89	4.48	26.82
Median (%)	0.00	0.00	0.00	0.19	0.73	3.62	22.07
Standard deviation	0.00	0.07	0.11	0.27	1.05	3.32	12.68
2008 default rates (%)	0.00	0.38	0.38	0.48	0.78	4.00	26.00
Latest four quarters (Q1 2011-Q4 2011) (%)	0.00	0.00	0.00	0.07	0.00	1.50	15.94
Difference between last four quarters and average	0.00	(0.02)	(0.08)	(0.17)	(0.89)	(2.98)	(10.88)
Number of standard deviations	0.00	(0.31)	(0.66)	(0.64)	(0.85)	(0.90)	(0.86)

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

2011 Summary

Below are some key takeaways from the 2011 defaulters:

- After hitting an all-time high of 265 defaults in 2009, the count of defaulting companies fell off considerably in 2011, to 53. This includes publicly and confidentially rated entities as well as entities that were not rated at the time of default (see chart 5).
- By count, the U.S. and associated tax havens (Bermuda and the Cayman Islands) accounted for the majority of defaults, with 39, while the other developed nations had seven, and Europe accounted for only four. Within the emerging markets, Israel, the United Arab Emirates, and the Russian Federation recorded one default each.
- Although distressed exchanges have remained popular over the last few years, missed principal or interest payments were responsible for the largest proportion of defaults in 2011, at 43% of the total. Distressed exchanges accounted for 23% of all defaults.
- As of Dec. 31, 2011, 12-month-trailing speculative-grade default rates had fallen considerably from a year earlier. The global speculative-grade default rate was 1.71% at the end of 2011, with breakouts of 1.98% in the U.S., 1.59% in Europe, and 0.58% in the emerging markets (see table 7). If we include all rated corporate entities, the default rates were 0.75% globally, 1.04% in the U.S., 0.34% in Europe, and 0.33% in the emerging markets.
- Of the 44 defaulters that were rated at the beginning of the year, 43 were speculative grade ('BB+' or lower). Of the remainder, nine were not rated at the beginning of the year, and one began the year rated investment grade.
- Of the entities that defaulted last year (and that had ratings as of Jan. 1, 2011), 77.3% were rated 'B-' or lower at the start of the year.
- Global corporate bond issuance declined in 2011, with 8,377 new issues coming to market during the year, down from 8,549 in 2010. Both the speculative-grade and investment-grade segments saw decreases, with high yield falling to 639, and investment grade dropping to 2,971. Some of the falloff in new issuance stemmed from the increase in unrated new issuance in 2011. At the issuer level, Standard & Poor's assigned first ratings on 712 entities in 2011, the third-highest annual total, though still down from 742 in 2010. We note that we consider companies that reemerge from default--including distressed exchanges--as new entities for the purposes of this study.
- After the downgrade of the U.S. in August, corporate bond spreads immediately widened and remained elevated for the remainder of the year. Speculative-grade corporate bond spreads finished 2011 at 723 basis points (bps), compared with 538 bps at the start of the year. Investment-grade spreads ended 2011 at 224 bps, compared with 177 bps on Jan. 1.
- Alongside corporate bond spreads, CDS spreads also were higher at the end of the year after tumultuous events with sovereigns. The Markit Partners five-year North American High-Yield composite index rose to 6.8 on Dec. 30 from 4.2 at the beginning of the year, and it reached a high of 8.8 on Oct. 3. The European and Emerging Markets' series also showed similar increases.
- The outstanding debt volume affected by defaults also fell in 2011, to $84.3 billion, after posting an all-time high of $627 billion in 2009 (see chart 6).
- Texas Competitive Electric Holdings Co. LLC was the single largest defaulter in 2011 based on debt volume. The company accounted for $32.46 billion in debt, which is nearly 40% of the total amount affected by defaults in 2011 (see table 5). Texas Competitive Electric completed a distressed exchange on April 20. The exchange was an "amend and extend," in which the company received lender consent to extend the maturities on a portion of its senior secured credit facilities to 2016-2017 from 2013-2014.
- The number of 'AAA' rated entities dropped significantly in 2011, as several 'AAA' rated financial institutions and insurance companies with ratings implicitly tied to that on the U.S. government were downgraded shortly after the Aug. 5 downgrade of U.S. debt. This leaves only four 'AAA' rated companies in the U.S.--all from nonfinancial sectors. They are Automatic Data Processing Inc., Johnson & Johnson, Microsoft Corp., and ExxonMobil Corp.
- Of the global total, five confidentially rated issuers defaulted.
- A total of six defaulters were initially rated 'BBB-' or higher, whereas 39 companies (74% of all defaults in 2011) were initially rated 'B+' or lower.
- Of the defaulted entities that Standard & Poor's initially rated investment grade, the average time to default--the time between first rating and date of default--was 17.4 years, with an associated standard deviation of 9.76 years.
- In contrast, the average time to default among entities initially rated 'BB+' or lower was 4.16 years, with an associated standard deviation of 3.45 years.
- For all of the issuers that defaulted in 2011, the average time to default from first rating was 5.66 years, and the median was 4.83 years.
- The issuer with the longest time to default in 2011 was U.S.-based AMR Corp., which took 30.9 years to default from its initial rating of 'BBB-'.

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- At the opposite end of the spectrum, the issuer with the shortest time to default--0.04 years--was U.S.-based transportation company Trailer Bridge Inc. The company failed to make principal and interest payments on its senior secured debt only 15 days after the rating on the company was raised to 'CC' after a prior selective default.
- As was the case in 2010, the consumer/service sector recorded the highest number of defaults worldwide relative to other sectors (11). All of the default activity in this sector occurred in the U.S.

Annual Global Trends

After a record number of corporate defaults in 2009, the count fell in 2011 for the second straight year (see chart 5), as did the amount of affected debt (see chart 6). As it has in the past, the U.S. accounted for the majority of both default counts and affected debt in 2011. This is mostly attributable to the larger rated population in the U.S. The largest defaulter by debt amount outstanding was Texas Competitive Electric Holdings Co. LLC., which extended the maturities on a portion of its senior secured credit facilities in April, thus constituting a distressed exchange. This, combined with its other outstanding issues, raised the issuer's total affected debt to $32.5 billion. Although sizable, this is a more modest amount compared with the largest defaulters of the previous three years (see table 5).

Default activity may have subsided in 2011, but rating actions (both upgrades and downgrades) and withdrawals were more frequent (see table 6). As they did in 2010, upgrades outnumbered downgrades in 2011, but by a smaller margin, pushing the downgrade-to-upgrade ratio to near parity at 0.96. The percentage of withdrawn ratings also increased in 2011. As a result of the rise in rating actions and withdrawals, the percentage of unchanged ratings fell below the series long-term average of 70.9%.

Table 5

Largest Global Rated Defaulters By Year

Largest corporate defaulters by outstanding debt amount

Year defaulted	Issuer	Amount (mil. $)
1991	Columbia Gas System	2,292
1992	Macy (R.H.) & Co.	1,396
1993	Mesa, Inc.	600
1994	Confederation Life Insurance	2,415
1995	Grand Union Co./Grand Union Capital	2,163
1996	Tiphook Finance	700
1997	Flagstar Corp.	1,021
1998	Service Merchandise Co.	1,326
1999	Integrated Health Services Inc.	3,394
2000	Owens Corning	3,299
2001	Enron Corp.	10,779
2002	WorldCom Inc.	30,000
2003	Parmalat Finanziaria SpA	7,177
2004	RCN Corp.	1,800
2005	Calpine Corp.	9,559
2006	Pliant Corp.	1,644
2007	Movie Gallery Inc.	1,225
2008	Lehman Brothers Holdings Inc.	144,426
2009	Ford Motor Co.	70,989
2010	Energy Future Holdings Corp.	47,648
2011	Texas Competitive Electric Holdings Co. LLC	32,460

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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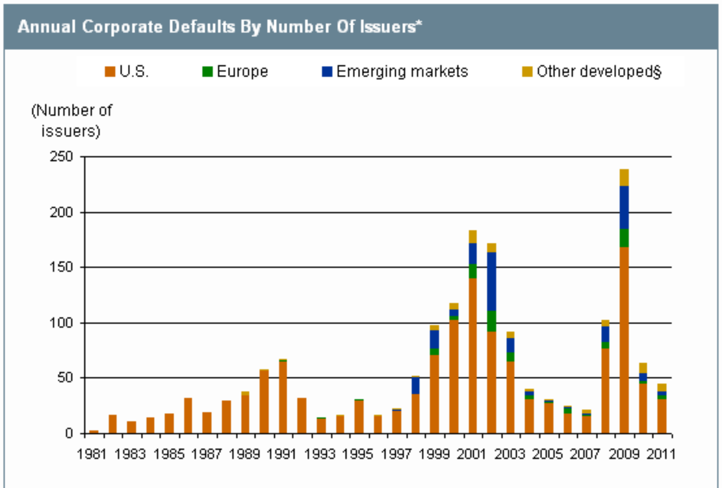
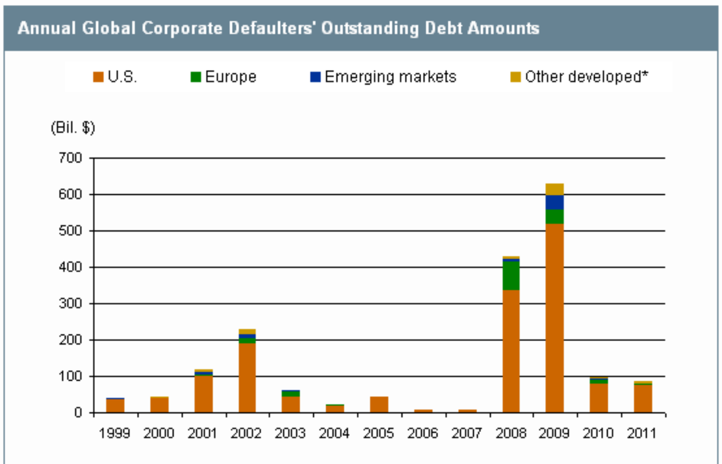
Chart 5



*Count excludes defaults that were not rated one year prior to default. §Other developed includes Australia, Canada, Japan, and New Zealand. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 6



*Other developed includes Australia, Canada, Japan, and New Zealand. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 6

Summary Of Annual Corporate Rating Changes* (%)

Year	Issuers as of Jan. 1	Upgrades	Downgrades¶	Defaults	Withdrawn ratings	Changed ratings	Unchanged ratings	Downgrade-to-upgrade ratio
1981	1,385	9.75	13.21	0.14	2.02	25.13	74.87	1.36
1982	1,433	5.86	12.63	1.19	5.30	24.98	75.02	2.15
1983	1,455	7.08	11.75	0.76	5.22	24.81	75.19	1.66
1984	1,542	11.15	9.99	0.91	2.85	24.90	75.10	0.90
1985	1,628	7.86	13.76	1.11	4.05	26.78	73.22	1.75
1986	1,857	7.22	15.83	1.72	6.89	31.66	68.34	2.19
1987	2,005	7.13	11.77	0.95	9.28	29.13	70.87	1.65
1988	2,093	8.89	11.80	1.39	8.22	30.29	69.71	1.33
1989	2,132	9.47	10.88	1.74	8.02	30.11	69.89	1.15
1990	2,117	6.14	15.30	2.74	6.61	30.80	69.20	2.49
1991	2,051	6.05	14.19	3.27	3.56	27.06	72.94	2.35
1992	2,140	9.35	11.21	1.50	4.02	26.07	73.93	1.20
1993	2,327	8.47	9.20	0.60	8.42	26.69	73.31	1.09
1994	2,562	6.99	9.21	0.62	4.61	21.43	78.57	1.32
1995	2,881	8.78	9.34	1.04	4.55	23.71	76.29	1.06
1996	3,143	9.45	7.57	0.51	7.00	24.53	75.47	0.80

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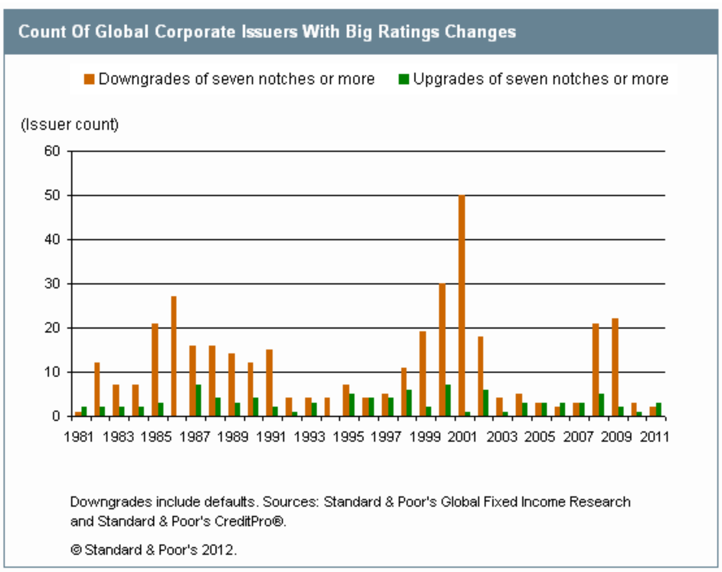
1997	3,506	9.07	7.81	0.63	7.30	24.81	75.19	0.86
1998	4,103	7.29	11.48	1.27	7.99	28.02	71.98	1.58
1999	4,549	5.56	11.47	2.13	8.79	27.95	72.05	2.06
2000	4,726	6.62	11.76	2.45	7.04	27.88	72.12	1.78
2001	4,806	5.56	15.83	3.77	7.51	32.67	67.33	2.85
2002	4,835	5.21	18.75	3.54	7.08	34.57	65.43	3.60
2003	4,845	6.26	14.29	1.90	7.31	29.76	70.24	2.28
2004	5,077	8.41	7.45	0.79	7.25	23.90	76.10	0.89
2005	5,368	12.56	9.04	0.58	8.44	30.61	69.39	0.72
2006	5,528	12.05	8.43	0.45	8.54	29.48	70.52	0.70
2007	5,730	13.21	9.09	0.37	10.32	32.99	67.01	0.69
2008	5,853	7.61	15.54	1.74	7.50	32.39	67.61	2.04
2009	5,772	4.65	18.51	4.06	8.37	35.59	64.41	3.99
2010	5,499	11.55	8.51	1.15	6.22	27.43	72.57	0.74
2011	5,851	11.87	11.41	0.75	7.39	31.42	68.58	0.96
Weighted average		8.49	11.84	1.57	7.23	29.13	70.87	1.64
Median		7.86	11.48	1.15	7.25	27.95	72.05	1.36
Standard deviation		2.33	3.08	1.06	1.99	3.49	3.49	0.84
Minimum		4.65	7.45	0.14	2.02	21.43	64.41	0.69
Maximum		13.21	18.75	4.06	10.32	35.59	78.57	3.99

*This table compares the net change in ratings from the first to the last day of each year. All intermediate ratings are disregarded. §Excludes downgrades to 'D', shown separately in the default column. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Although the percentage of global corporate issuers that experienced ratings changes may have increased in 2011, the upgrades and downgrades were mild in magnitude. Only two entities experienced downgrades of seven notches or more in 2011. This is roughly in line with the three in 2010 and is the lowest level since 2006, when the total was also two (see chart 7). The issuers that experienced significant downgrades in 2011 were MF Global and New Zealand-based Western Pacific Insurance Ltd., both of which were downgraded to 'D'.

Chart 7



The overall issuer-weighted default rate--including both investment-grade and speculative-grade entities-was 0.75% in 2011, the lowest since 2007. By region, the corresponding rates were 1.04% in the U.S., 0.34% in Europe, and 0.33% in the emerging markets.

Despite titanic developments in U.S. and European credit markets, default activity was muted in many regions in 2011. On a trailing-12-month basis, the global speculative-grade default rate fell to 1.7% in 2011 from 2.8% at the end of 2010 and is now solidly below its long-term average of 4.3%. In the U.S. region, the speculative-grade default rate was 1.98% at the end of 2011, down from 3.3% in 2010 and well below the 4.4% long-term average. Within Europe, the speculative-grade default rate rose to 1.6% from 1% in 2010 but remains below the region's 3.2% long-term average. In the emerging markets, the speculative-grade default rate finished 2011 just below 0.6%, its lowest level since 2007 (see table 7 and chart 21). Among all major regions, the only to still experience a relatively higher speculative-grade default rate for 2011 was the other developed region.

Table 7

Annual Corporate Speculative-Grade Default Rates By Region (%)

Year	U.S. and tax havens*	Europe§	Emerging markets	Other†

1981	0.63	0.00	N/A	0.00
1982	4.44	0.00	N/A	0.00
1983	2.98	0.00	N/A	0.00
1984	3.32	0.00	0.00	0.00
1985	4.39	0.00	N/A	0.00
1986	5.74	0.00	N/A	0.00
1987	2.83	0.00	N/A	0.00
1988	3.88	0.00	N/A	0.00
1989	4.31	0.00	N/A	50.00
1990	7.91	0.00	N/A	40.00
1991	10.69	66.67	N/A	16.67
1992	6.23	0.00	N/A	0.00
1993	2.39	20.00	0.00	0.00
1994	2.19	0.00	0.00	0.00
1995	3.64	9.09	0.00	0.00
1996	1.85	0.00	0.00	2.78
1997	2.17	0.00	0.00	1.96
1998	3.24	0.00	8.02	1.45
1999	5.23	5.62	7.42	4.49
2000	7.33	2.52	1.86	6.67
2001	10.54	8.53	6.25	12.64
2002	7.14	12.50	15.77	6.06
2003	5.54	3.70	3.57	4.85
2004	2.50	1.63	0.77	2.03
2005	2.00	0.48	0.22	1.33
2006	1.29	1.87	0.40	0.77
2007	1.01	1.02	0.19	2.24
2008	4.13	2.63	2.20	3.85
2009	11.19	8.02	6.17	10.48
2010	3.29	1.01	1.25	7.89
2011	1.98	1.60	0.59	5.98
Average	4.39	3.20	3.42	4.72
Median	3.64	1.75	1.55	4.17
Standard deviation	2.82	3.65	4.34	3.43
Minimum	0.63	0.00	0.00	0.77
Maximum	11.19	12.50	15.77	12.64

*U.S., Bermuda, and the Cayman Islands. §Austria, Belgium, Bulgaria, Channel Islands, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the U.K. †Australia, Canada, Japan, and New Zealand. N/A--Not available. Note: Descriptive statistics for regions other than the U.S. are calculated from 1996 to 2011 because of sample sizes. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Data on defaulted corporate issuers globally indicate that defaults among speculative-grade entities tend to be clustered in the third year after the initial rating, particularly in the 'B' rating category (see chart 8). For example, among defaulters that were rated 'B' at origination, the default rate climbs to a high of 19.1% in the first three years and then decelerates thereafter. Defaulted issuers initially rated 'BB' show a similar pattern but peak a little later--in the fourth year. Conversely, defaulters initially rated 'CCC' show the reverse, with the highest default rate observed in the first year, which is not surprising given the low rating.

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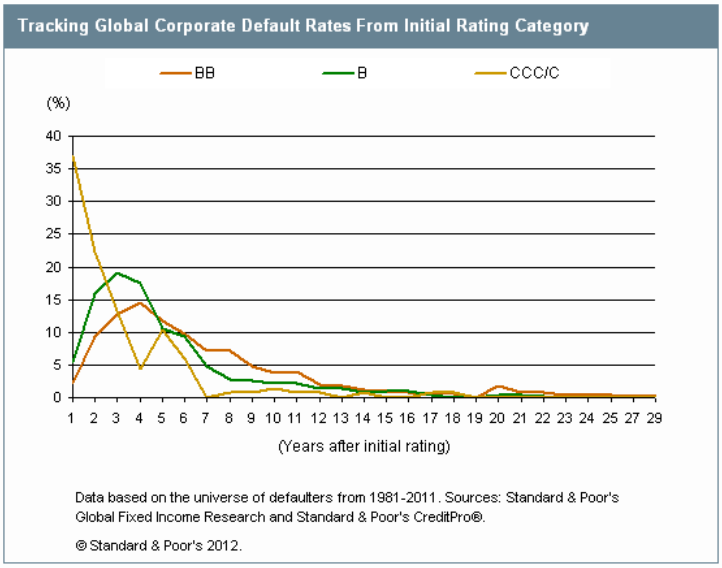
Chart 8



In 2011, 47 (or 89%) of the 53 defaulted entities were originally rated speculative grade ('BB+' or lower), which is slightly higher than the long-term average of 85.9%. This is typical in years with lower default rates. The rating path observed for defaulters in the trailing 12 quarters is broadly representative of the long-term ratings trend, which shows that both the average rating and median rating on all defaulting entities were in the speculative-grade category in the five years preceding default (see chart 9).

Financial institutions and insurance companies are particularly sensitive to sudden declines in investor confidence, which can result in a relatively fast descent into default (see chart 10). This was especially evident during the recent financial crisis, as many highly rated banks defaulted within a short amount of time from their initial downgrades during this period. Conversely, nonfinancial defaulters travel a much slower, smoother, and shorter path to default (see chart 11).

Chart 9

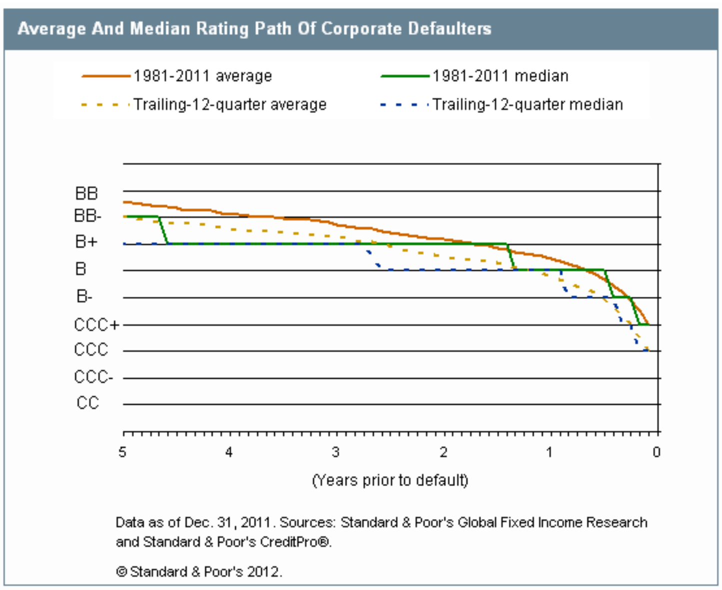


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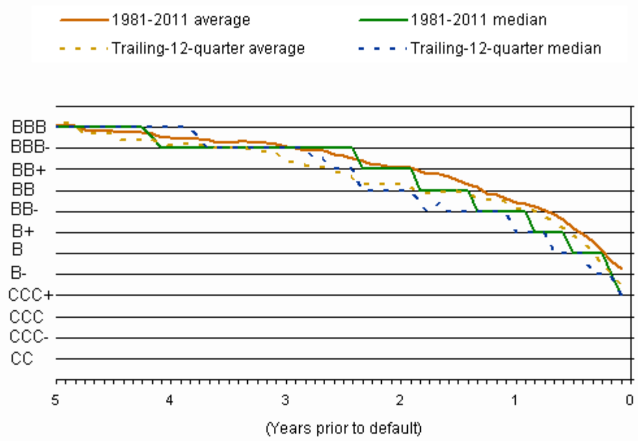
Chart 10

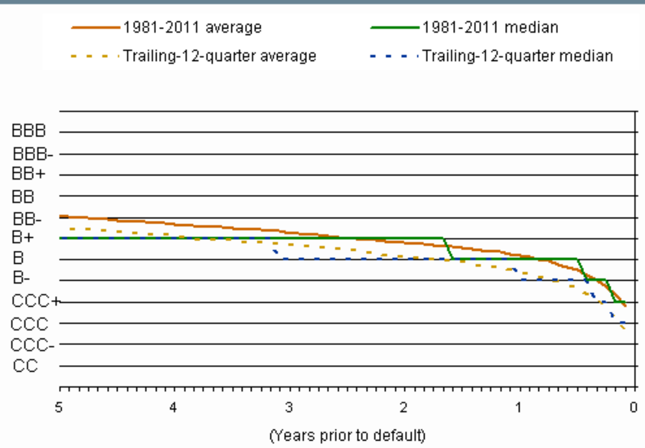
Average And Median Rating Path Of Financial Defaulters*



*Financial sector includes insurance companies and financial institutions. Data as of Dec. 31, 2011. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 11

Average And Median Rating Path Of Nonfinancial Defaulters



Data as of Dec. 31, 2011. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Some issuers default when they are no longer rated (NR) by Standard & Poor's. We make our best effort to capture such defaults in the database, and we include them in the annual default rate calculations if an entity was rated as of Jan. 1 in the year of default. If, however, Standard & Poor's withdrew the rating prior to Jan. 1 of the year of default, we did not include the issuer in the default rate calculation in that year. Of the 53 defaulted companies in 2011, 9.4% were not rated just prior to default, which is roughly half the long-term average of 18.7% (see chart 12A). Furthermore, although 'NR' defaulters are not always captured in the default rate calculation for the year of default, we do capture such defaults in the longer-term cumulative default rate statistics, tagged back to the year in which they were last rated. Charts 12A and 12B also present another example testifying to the broadly positive performance of corporate ratings and the credit environment as a whole. All of the defaulters in 2011 that had active ratings immediately prior to default were rated in the lowest rating categories. In particular, 83% were rated 'CCC+' or lower prior to default, much higher than the 62.4% long-term average.

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Chart 12A

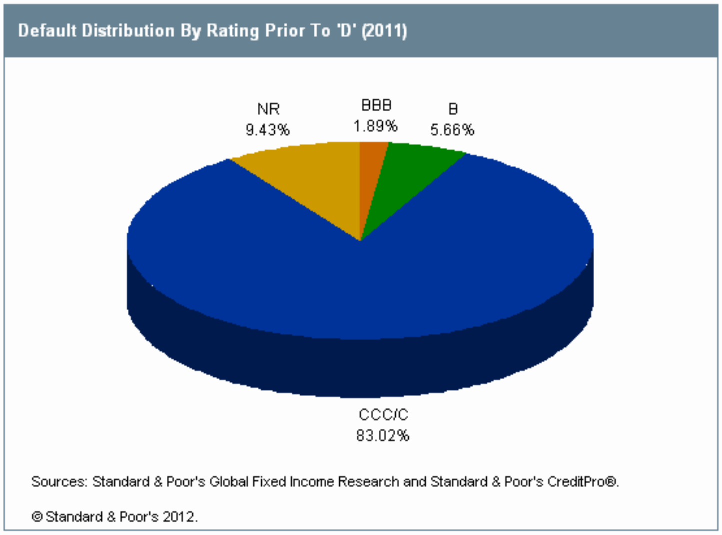

Chart 12B

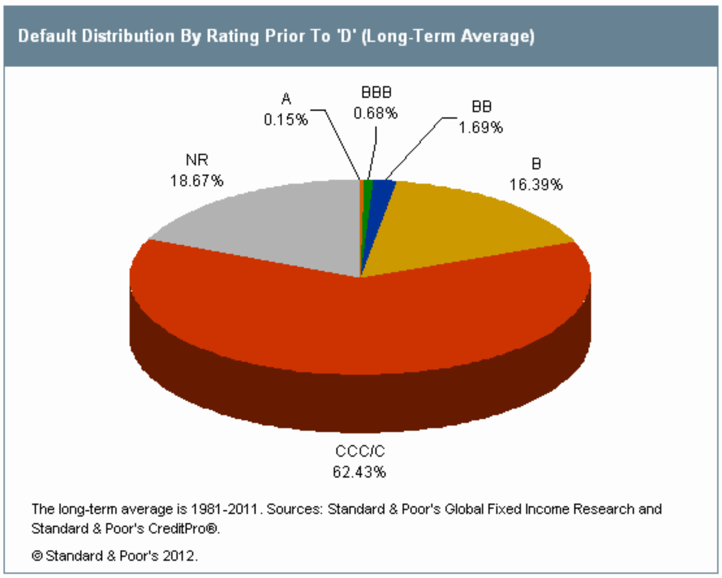

Table 8 provides a list of all the nonconfidentially rated defaults recorded in 2011. For details on the 2011 defaulters, see "**2011 Default Synopses**."

Table 8

2011 Global Corporate Defaults

Company name	Reason for default	Country	Industry	Debt amount (mil. $)	Default date	Next-to-last rating	Date of next-to-last rating	First rating	Date of first rating
SAZKA a.s.	Missed	Czech Republic	Leisure time/media	203.0	1/13/2011	CC	12/17/2010	BB-	8/10/2004
Sbarro Inc.	Missed	U.S.	Cons/service	347.9	2/1/2011	CC	1/6/2011	BB-	9/3/1999
Confidential Company	Ch. 11	U.S.	Cons/service	2,144.1	2/16/2011	NR	10/31/2007	B-	7/13/2007
Ahern Rentals Inc.	Missed	U.S.	Aero/auto/CG/metal	617.5	2/16/2011	B-	6/21/2010	B	8/2/2005
Harry & David Operations Corp.	Missed	U.S.	Cons/service	303.4	3/7/2011	CC	1/20/2011	B	2/9/2005
Western Pacific Insurance Ltd.	Regulatory directive	New Zealand	Insurance	0.0	4/4/2011	B	1/7/2009	B-	3/30/2006
GFNZ Group Ltd.	Distressed exchange	New Zealand	Financial institutions	30.0	4/5/2011	CC	3/17/2011	CCC	3/30/2010
Perkins & Marie Callender's Inc.	Missed	U.S.	Cons/service	344.2	4/7/2011	CC	12/22/2010	B+	12/11/1997

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Confidential Company	Missed	United Arab Emirates	Real estate	63.0	4/8/2011	B-	10/27/2010	B-	10/27/2010
Liz Claiborne Inc.	Distressed exchange	U.S.	Cons/service	759.7	4/11/2011	CC	3/11/2011	BBB	11/16/1999
Cinram International Inc.	Distressed exchange	Canada	Leisure time/media	936.0	4/12/2011	CC	1/27/2011	B	5/22/2009
SOTSGORBANK	Receivership	Russian Federation	Financial institutions	0.0	4/19/2011	CCC	3/4/2011	CCC	6/21/2006
Texas Competitive Electric Holdings Co. LLC	Distressed exchange	U.S.	Energy and natural resources	32,460.3	4/20/2011	CC	4/4/2011	B-	11/17/2009
Keystone Automotive Operations Inc.	Distressed exchange	U.S.	Cons/service	445.6	4/28/2011	CC	11/23/2010	B+	10/15/2003
Berkline/BenchCraft Holdings LLC	Ch. 11	U.S.	Cons/service	0.0	5/2/2011	NR	9/12/2006	B+	9/29/2004
Caribe Media Inc	Ch. 11	U.S.	Leisure time/media	464.0	5/6/2011	CCC-	8/23/2010	B	3/2/2006
OPTI Canada Inc.	Missed	Canada	Energy and natural resources	2,743.1	6/16/2011	CCC-	12/14/2010	BB	4/12/2006
Novasep Holding S.A.S.	Missed	France	Health care/chemicals	533.8	6/22/2011	CCC+	4/5/2011	B	12/7/2009
Confidential Company	Ch. 11	U.S.	Cons/service	155.0	6/26/2011	NR	6/23/2011	CC	10/13/2009
NBC Acquisition Corp.	Ch. 11	U.S.	Cons/service	527.0	6/27/2011	CCC	4/5/2011	B+	2/10/1998
Real Mex Restaurants Inc.	Missed	U.S.	Cons/service	220.0	7/20/2011	CCC	6/24/2011	B	3/12/2004
NZF Money Ltd.	Receivership	New Zealand	Financial institutions	0.0	7/25/2011	CC	7/21/2011	B	2/23/2010
YRC Worldwide Inc.	Distressed exchange	U.S.	Transportation	816.3	7/27/2011	CC	3/16/2011	CCC-	1/11/2010
William Lyon Homes	Missed	U.S.	Forest products	485.8	8/19/2011	CCC-	6/6/2011	CCC-	6/16/2009
PMI Mortgage Insurance Co.	Regulatory supervision	U.S.	Insurance	285.0	8/22/2011	CCC-	8/4/2011	AA	3/8/1985
Global Aviation Holdings Inc.	Missed	U.S.	Transportation	230.2	8/23/2011	CCC+	8/16/2011	B	7/20/2009
Horizon Lines Inc.	Missed	U.S.	Transportation	598.2	8/23/2011	CCC	3/29/2011	B	9/30/2005
Confidential Company	Missed	Israel	Real estate	461.0	9/7/2011	CC	7/27/2011	CCC+	10/28/2010
NewPage Corp.	Ch. 11	U.S.	Forest products	3,227.8	9/7/2011	CCC	8/15/2011	CCC+	10/5/2009
General Maritime Corp.	Missed	U.S.	Transportation	2,165.7	10/4/2011	CCC+	12/9/2010	BB	3/4/2003
Real Mex Restaurants Inc.	Missed	U.S.	Cons/service	210.2	10/4/2011	CC	8/5/2011	CC	8/5/2011
Travelport Holdings Ltd.	Distressed exchange	U.S.	Transportation	7,428.8	10/5/2011	CC	9/21/2011	CCC	9/13/2011
Yioula Glassworks S.A.	Missed	Greece	Forest products	419.2	10/7/2011	CCC+	6/23/2010	B+	11/7/2005
William Lyon Homes	Missed	U.S.	Forest products	485.8	10/11/2011	CC	9/20/2011	CC	9/20/2011
Wastequip Inc.	Confidential	U.S.	Aero/auto/CG/metal	371.5	10/19/2011	CCC-	9/29/2011	CCC	9/22/2010
Trailer Bridge Inc.	Confidential	U.S.	Transportation	204.4	10/26/2011	CCC	6/10/2011	B-	11/10/2004
MF Global Holdings Ltd.	Ch. 11	U.S.	Financial institutions	2,517.0	10/31/2011	BBB-	11/24/2010	BBB+	5/31/2007
Hovnanian Enterprises Inc.	Distressed exchange	U.S.	Forest products	1,386.5	11/2/2011	CC	10/5/2011	CCC+	10/5/2009
River Rock Entertainment Authority	Missed	U.S.	Leisure time/media	200.0	11/2/2011	CCC	10/28/2011	B+	10/23/2003
Dynegy Holdings LLC	Ch. 11	U.S.	Energy and natural resources	5,209.8	11/8/2011	CC	3/18/2011	BBB-	9/28/1995
SEAT PagineGialle SpA	Missed	Italy	Leisure time/media	3,833.5	11/8/2011	CC	11/1/2011	BB-	4/6/2004
Chukchansi Economic Development Authority	Missed	U.S.	Leisure time/media	310.0	11/15/2011	NR	11/3/2011	BB-	10/24/2005
Trailer Bridge Inc.	Missed	U.S.	Transportation	204.4	11/16/2011	CC	11/1/2011	CC	11/1/2011
PMI Group Inc.	Ch. 11	U.S.	Insurance	1,045.0	11/28/2011	CC	8/4/2011	A+	11/6/1996
AMR Corp.	Ch. 11	U.S.	Transportation	3,138.2	11/29/2011	CCC+	11/17/2011	BBB-	12/31/1980
Confidential Company	Ch. 11	U.S.	Leisure time/media	1,886.7	12/12/2011	NR	4/23/2007	BB	4/5/2005
Broadlands Finance Ltd.	Missed	New Zealand	Financial institutions	0.0	12/15/2011	CC	12/8/2011	BB-	2/24/2010
Aquilex Holdings LLC	Distressed exchange	U.S.	Health care/chemicals	438.2	12/16/2011	CC	11/21/2011	B	11/20/2008

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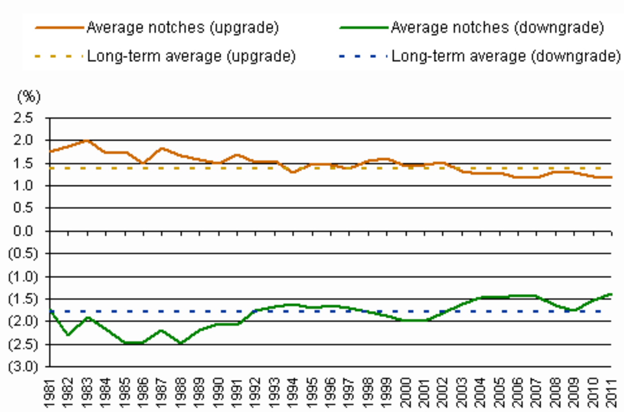
Catalyst Paper Corp.	Missed	Canada	Forest products	761.8	12/16/2011	CCC	8/8/2011	CCC+	3/15/2010
GMX Resources Inc.	Distressed exchange	U.S.	Energy and natural resources	444.5	12/16/2011	CC	11/30/2011	B-	4/21/2011
SuperMedia Inc.	Distressed exchange	U.S.	Leisure time/media	1,839.8	12/16/2011	CC	11/16/2011	B-	12/29/2010
Delta Petroleum Corp.	Ch. 11	U.S.	Energy and natural resources	265.0	12/19/2011	CCC-	11/11/2011	B-	3/1/2005
Dune Energy Inc.	Distressed exchange	U.S.	Energy and natural resources	92.5	12/23/2011	CC	10/11/2011	CCC-	12/31/2009
		Total		84,260					

Aero/auto/CG/metal--Aerospace/automotive/capital goods/metal. High tech--High technology/computers/office equipment. Forest products--Forest and building products/homebuilders. Cons/service--Consumer/service sector. Ch. 11--Chapter 11. Missed--Missed interest or principal payment. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®

As demonstrated earlier, large notch movements diminished in number in 2011. This also applies to the average notch movement relative to prior years. In terms of both upgrades and downgrades, 2011 saw the most muted levels of both average upgrades and downgrades in absolute terms (see chart 13). At the end of 2011, the average notch upgrade was 1.16, and the average notch downgrade was 1.4. These deviations from the long-term averages are the largest for both series since before the turn of the century.

Chart 13

Average Notch Movements Among Global Rating Actions



Long-term average based on data from 1981-2011. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 9

One-Year Global Corporate Default Rates By Rating Modifier (%)

	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.28	0.00	0.00
1982	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.00	0.68	0.00	0.00	2.86	7.04	2.22	2.33	7.41	21.43
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.33	2.17	0.00	1.59	1.22	9.80	4.76	6.67
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	1.64	1.49	2.13	3.51	7.69	25.00
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.64	1.49	1.33	2.59	13.11	8.00	15.38
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.78	0.00	0.78	0.00	1.82	1.18	1.12	4.65	12.16	16.67	23.08
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	1.31	5.95	6.82	12.28
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.34	1.98	4.50	9.80	20.37
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	0.78	0.00	0.00	0.00	2.00	0.43	7.80	4.88	33.33
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	1.10	2.78	3.06	4.50	4.87	12.26	22.58	31.25
1991	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84	0.74	0.00	3.70	1.12	1.05	8.72	16.25	32.43	33.87
1992	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.72	14.93	20.83	30.19
1993	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.92	0.00	1.30	5.88	4.17	13.33
1994	0.00	0.00	0.00	0.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.86	0.00	1.83	6.58	3.23	16.67
1995	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.63	0.00	1.55	1.11	2.76	8.00	7.69	28.00
1996	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.88	0.65	0.55	2.34	3.74	3.92	4.17
1997	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.34	0.00	0.00	0.00	0.41	0.72	5.26	14.58	12.00
1998	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	1.04	0.68	1.06	0.72	2.58	7.56	9.46	42.86
1999	0.00	0.00	0.00	0.36	0.00	0.24	0.27	0.00	0.28	0.31	0.55	1.34	0.90	4.21	10.50	15.45	33.33
2000	0.00	0.00	0.00	0.00	0.00	0.24	0.56	0.00	0.26	0.88	0.00	0.81	2.32	5.77	10.66	11.50	34.12
2001	0.00	0.00	0.00	0.00	0.57	0.48	0.00	0.24	0.48	0.27	0.51	1.21	6.03	5.96	15.68	23.31	45.87
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.12	0.66	1.32	1.55	1.77	4.65	3.69	9.63	19.69	44.64
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.53	0.49	0.95	0.28	1.71	5.24	9.45	33.13

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2004	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.00	0.00	0.66	0.77	0.46	2.70	2.84	15.56
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.37	0.00	0.25	0.78	2.63	2.98	9.02
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.49	0.55	0.80	1.57	12.38
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.23	0.19	0.00	0.90	14.95
2008	0.00	0.00	0.44	0.40	0.31	0.21	0.58	0.19	0.59	0.72	1.18	0.65	0.65	3.04	3.39	7.56	26.00
2009	0.00	0.00	0.00	0.00	0.29	0.39	0.00	0.40	0.19	1.10	0.00	1.04	0.93	5.63	10.23	17.63	48.68
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.80	0.36	0.53	0.00	0.69	2.07	22.07
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.39	1.19	3.99	15.94
Average	0.00	0.00	0.01	0.02	0.05	0.07	0.07	0.16	0.25	0.30	0.63	0.86	1.42	2.41	6.98	9.80	23.41
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.81	0.83	1.98	5.95	7.69	22.07
Standard deviation	0.00	0.00	0.08	0.10	0.14	0.14	0.20	0.32	0.35	0.46	0.94	0.84	1.78	2.13	4.67	7.89	12.68
Minimum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum	0.00	0.00	0.44	0.40	0.57	0.48	0.78	1.12	1.40	1.33	3.70	3.06	7.04	8.72	16.25	32.43	48.68

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

2011 Timeline: Sovereigns Take Center Stage

After 2010 finished in generally positive terms for financial markets, 2011 got off to an uneventful, if not positive start. However that ultimately changed, as events in sovereign debt markets had effects that spilled over to corporate borrowers. In North America, the unprecedented downgrade of the U.S. in early August rocked equity markets, albeit relatively briefly, while the impact on corporate debt markets was more prolonged. In Europe, a series of sovereign downgrades and the seemingly perpetual prospect of a default by Greece contributed to a lethargic recovery globally. As the year progressed, volatility permeated equity markets, while corporations' borrowing costs rose, as did the cost of insuring that debt in the event of a default. Default activity remained muted throughout most of the year, though it picked up in the fourth quarter, which pointed to more investor uncertainty and caution heading into the new year.

After gaining roughly 11% in 2010, the Dow Jones Industrial Average (DJIA) started the year at 11,578, still pushing forward in its long recovery from a low of 6,547 on March 9, 2009. Equity market volatility, as measured by the Chicago Board Options Exchange Market Volatility Index (VIX), was also relatively benign at the start of the year, at 17.6 on Jan. 3. In a potential sign of market demand to come, social network giant Facebook raised $500 million in a private offering spearheaded by Goldman Sachs on Jan. 4, valuing the company at $50 billion. From there, it didn't take long for dramatic headlines to hit. After weeks of civilian protests and clashes with authorities, in mid-January Tunisian President Zine el-Ablidine Ben Ali was overthrown, with the remaining politicians setting up a caretaker government in place until new elections are held. This was the beginning of a series of protests and civil wars across the Arab world that resulted in the departure of several existing governments in the region.

Later in the month, protests broke out in Egypt, the Arab world's most populous country, which resulted in President Hosni Mubarak stepping down from office on Feb. 11. Meanwhile, on the economic and financial fronts, official numbers came in during February to confirm that China had overtaken Japan in 2010 to become the world's second-largest economy. Given China's sustained remarkable growth rates, in April the International Monetary Fund (IMF) estimated that it would overtake the U.S. as the world's largest economy (based on comparative purchasing power) by 2016--the first time the IMF has put a time frame on the event.

Toward the end of February, antigovernment protests turned into outright rebellion in Libya, resulting in a brief civil war. Many of the country's ports came under attack and ultimately closed, cutting off Libyan oil exports. In early March, President Obama called for long-time Libyan leader Moammar Gadhafi to give up power. As these events unfolded, markets reacted, pushing the VIX up above 20 for the first time in the year.

Meanwhile, New Zealand experienced a 6.3 magnitude earthquake in Christchurch, the country's second-largest city. Only a week or so later, a 9.0 magnitude earthquake and subsequent tsunami hit Japan. The devastation from the tsunami caused significant damage to the country's nuclear reactors and disrupted regional and global supply chains for an extended period. Japan's Nikkei dropped more than 6% on its first day of trading after the disaster, and the DJIA followed suit. Shortly after, the VIX, U.S. corporate bond spreads, and credit default swap (CDS) rates all spiked briefly.

On April 7, Portugal announced it would ask the EU for a financial bailout. This came a week after the country's second downgrade since the beginning of 2011, bringing the country to within one notch of a speculative-grade rating. Only a few weeks later, on the other side of the Atlantic, President Obama called for a plan to reduce the U.S. deficit by $4 trillion in the next 12 years through a combination of increasing revenue and reductions in spending. Not convinced a compromise would be reached, Standard & Poor's revised its outlook on the U.S. to negative on April 18. On April 23, antigovernment protests spread to Syria, where the clashes between civilians and security forces were more intense than in other countries, with the exception of Egypt. The political upheaval across the Arab world sparked multiple downgrades throughout the year. Standard & Poor's downgraded Bahrain, Tunisia, and Jordan twice each, and it lowered its ratings on Egypt three times, to 'B+' from 'BBB-' at the beginning of the year.

On May 9, Standard & Poor's downgraded Greece for the second time in 2011, citing an increased likelihood of a rescheduling of the country's commercial debt, which would constitute a selective default. Throughout the first half of 2011, corporate borrowing costs remained near record lows, opening the door to additional funding. Corporate lending conditions were so attractive that on May 17, Google went to market with its first debt issue. The total was $3 billion. Standard & Poor's first assigned a rating on Google on July 15, 2010. Meanwhile, reminders of the extent of the recent financial crisis appeared. In positive news, on May 25, the U.S. Treasury and American International Group (AIG) sold $8.7 billion worth of shares in a stock offering. It produced a small profit for taxpayers nearly two and a half years after the government provided AIG with a massive bailout. Despite this bit of positive news in the aftermath of the crisis, housing information released on June 1 indicated that home prices within the U.S. had retreated to levels not seen since 2002.

The third quarter of 2011 began with increased stress on sovereigns. On July 6, Moody's downgraded Portugal to speculative grade (Standard & Poor's later downgraded Portugal two notches, to 'BB', on Jan. 13, 2012). A week later, Moody's also downgraded Ireland to speculative-grade status, and on July 27, Standard & Poor's lowered its rating on Greece for the last time in 2011--to 'CC'--in anticipation of its eventual selective default.

In mid-July, amid the possibility that the U.S. Congress would not raise the debt limit in time, the ratings agencies warned of a possible downgrade of the U.S. government. The political bickering carried on for the rest of the month, until eventually the debt ceiling was raised on Aug. 1. Although this was passed before the official deadline, Standard & Poor's lowered its debt rating on the U.S. on Aug. 5. This wasn't a surprise, but it was still an unprecedented move. The downgrade had enormous repercussions for 'AAA' rated entities in the U.S.--more than 82% of them were subsequently downgraded to 'AA+'. Borrowing costs for U.S.- based corporations also increased, and not just at the highest rating levels. The speculative-grade corporate bond spread widened by more than 46 basis points (bps) by the close of the next business day, and it continued to rise before reaching a high of 830 bps on Oct. 4. CDS markets also responded to the news, with the Markit North American High-Yield series expanding by more than 1% by the end of the next business day as well. This series spiked to nearly 9% by October from a low for the year of 3.8% in early February. Perhaps contrary to expectations, the yield on the U.S. Treasury's 10-year note dropped below 2% by the end of September as investors search for a safe-haven investment intensified.

Despite the market volatility, defaults within the corporate sector remained muted. In September, only two companies defaulted globally. The impact on consumers, however, was becoming more severe. On Sept. 14, statistics released showed that the median family income in the U.S. dropped to 1996 levels, well before the recent financial crisis began. In an effort to boost the economy yet again, the Federal Reserve implemented another round of open market transactions similar to QE1 and QE2, this time referred to as "Operation Twist," in which the Fed purchased $2.65 trillion of long-term Treasuries by selling an equivalent amount of shorter-term government debt with the aim of lowering long-term rates for the real economy. Internationally, Standard & Poor's downgraded Italy by one notch to 'A' on Sept. 19 amid more concerns over Europe. Standard & Poor's also lowered its ratings on Belarus and Ukraine during the month, but both were already solidly in speculative-grade territory.

In yet another sign of continued uneasiness regarding Europe, Standard & Poor's downgraded Spain on Oct. 13 owing to uncertainty in its financial system as well as its debt load and persistently high unemployment levels. This came just days after other ratings agencies downgraded both Spain and Italy. At this time, both the high-yield corporate spread in the U.S. and the Markit North American High–Yield CDS series hit their highs for 2011--suggesting that market disruptions in one region spread to others in the developed world.

Corporate defaults increased in October, to eight globally, up from two in September and four in August. Among these was the only investment-grade defaulter of 2011--MF Global, which filed for Chapter 11 bankruptcy protection on Oct. 31. Shortly after filing for bankruptcy, the firm came under increased scrutiny for approximately $1.2 billion worth of customer funds that it could not account for. The U.S. municipal debt market also took a hit in October with the bankruptcy filing of Harrisburg, Pennsylvania, the state's capital.

November was no less calm for global financial markets. Early in the month, European leaders called for Greece to formally declare its intention to remain a member of the eurozone after the Greek prime minister called for a referendum on the bailout plan. In terms of rating actions, Standard & Poor's downgraded eight sovereigns in November, and eight corporate entities defaulted in the month.

In the final month of 2011, the Fed and other central banks made coordinated efforts to make borrowing and lending easier for European banks. Much of this would involve dollar loans to foreign banks at favorable rates with the intention of providing more liquidity and time to the European region in the hopes that leaders there could work out a solution in the meantime. Nonetheless, markets remained skeptical about policymakers' ability to contain the turmoil in Europe, as reflected in the declining value of the euro. Many central banks within Europe even began planning for the possibility of countries leaving the eurozone or even of the currency zone falling apart. The European Central Bank also extended nearly $650 billion in low-interest loans to lenders in the region.

Over the course of 2011, the high-yield corporate bond spread within the U.S. jumped by nearly 200 bps to 723 bps from 538 bps at the beginning of the year. The price to insure against default increased markedly in both North America and Europe, as measured by the Markit North American High Yield and the iTraxx European CDS series, which expanded to 6.8% and 1.7%, respectively, from 4.2% and 1%. Perhaps surprisingly, equity markets fared slightly better in 2011, with the DJIA finishing the year up 6%. Volatility in U.S. equities hit a high point shortly after Standard & Poor's downgraded the U.S., but, by the end of December, it returned to more benign levels seen earlier in the year. Still, eight more corporate entities defaulted in December, with close to half (45.3%) of all global corporate defaults occurring in the fourth quarter alone. Europe continued to make minimal progress in the beginning of 2012, with Greece selectively defaulting as any final resolution remains uncertain. 2011 may have begun favorably for investors--especially considering the gyrations of 2010--but it finished with more uncertainty for the future than it began with. The economic and financial situation is marginally better in the U.S., though uncertainty in Europe could continue, with a possible fallout globally.

Quarterly Trends

Although the total number of defaults in 2011 was lower than in 2010, fourth-quarter 2011 saw a noticeable increase relative to the prior six quarters (see chart 14). This increase stands in contrast to the five in the first quarter of the year, which was the lowest quarterly amount since the third quarter of 2007. Similarly, the volume of debt affected by defaults fell in the first quarter, to $3.8 billion, but it rose to nearly $35 billion in the fourth quarter (see chart 15). During 2011, the second quarter produced $39.5 billion in affected debt, but this was mostly attributable to Texas Competitive Electric Holdings' $32.5 billion in outstanding debt.

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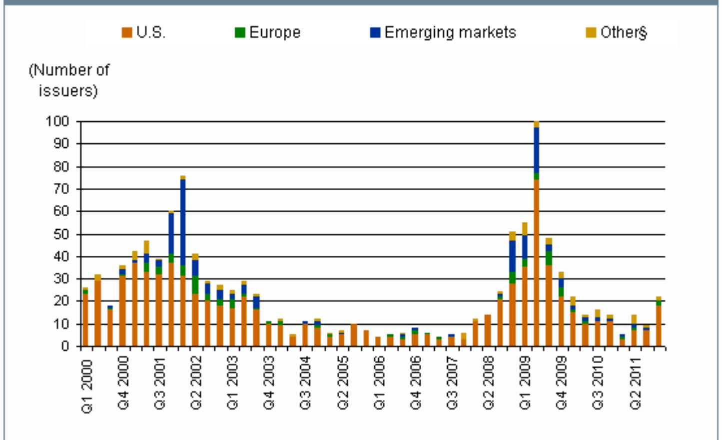
Chart 14

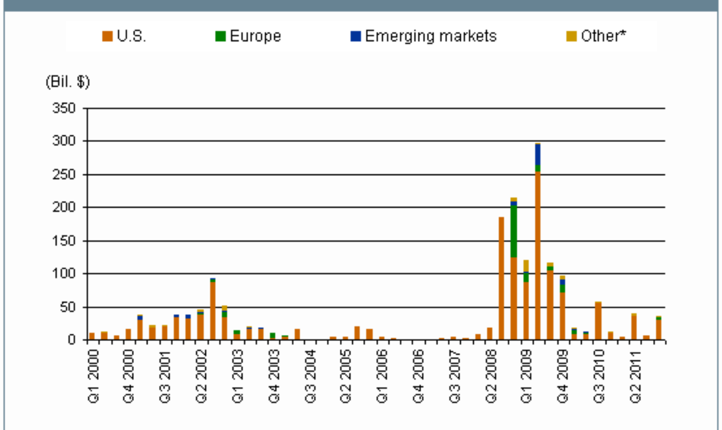
Quarterly Corporate Defaults By Number Of Issuers*



*Count excludes defaults that were not rated one quarter prior to default. §Other developed includes Australia, Canada, Japan, and New Zealand. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 15

Quarterly Global Corporate Defaulters' Debt Amounts Outstanding



*Other developed includes Australia, Canada, Japan, and New Zealand. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

The 12-month-trailing and annual default rates have become industry standards, but default rates measured over shorter time frames give a more immediate picture of credit market conditions. With this in mind, based on quarterly intervals of measurement (nonannualized), default activity appears to have been on the upswing at the end of 2011, with global, U.S., and European default rates at their highest points in the year (see chart 16).

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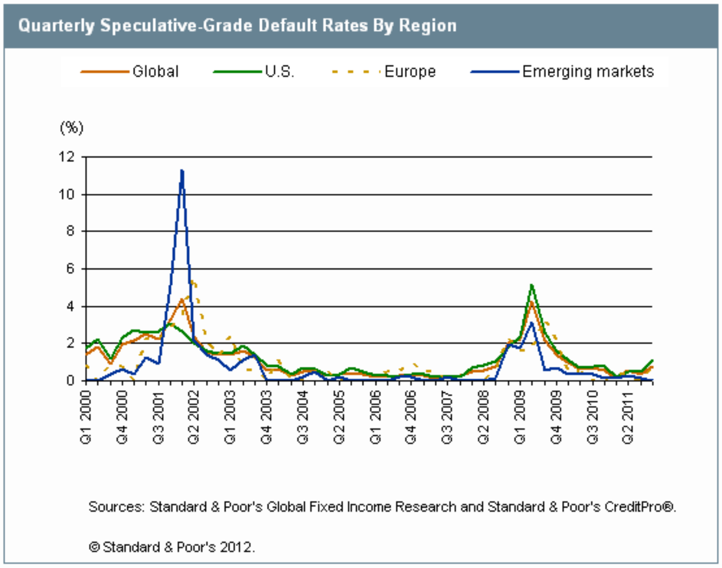
Chart 16



Lower Ratings Are Consistent With Higher Default Vulnerability

On average, there is a negative correlation between the initial rating on a firm and its time to default, if that were to occur. For example, for the entire pool of defaulters (1981-2011), the average times to default for issuers that were originally rated in the 'A' and 'B' categories were 12.6 years and 4.7 years, respectively, from initial rating (or from Dec. 31, 1980, the start date of the study), whereas issuers in the 'CCC' rating category or lower had an average time to default of only 2.5 years. In cases where an entity emerges from a prior default (including distressed exchanges), we consider it a separate entity, with the original rating as the first after the default event. Table 10 displays the median, average, and standard deviations for the time to default from the original rating. The differences between each rating category's minimum and maximum times to default are also presented in the last column under "range." Table 11 presents the average and median times to default from each rating category and includes both rating originations as well as transitions to each category. In both cases, the standard deviation of the times to default shrinks progressively as the rating gets lower. Generally speaking, the average time to default for each rating category is longer when based on the initial rating on an issuer than it is based on ratings reached later in the issuer's history. The notable exception to this is the 'AAA' category, which shows a slightly longer average time to default (see table 11), though this is a function of the small sample size. In total, seven issuers initially rated 'AAA' and another nine issuers that were rated 'AAA' at some point during their history have defaulted.

Table 10

Time To Default From Original Rating For Global Corporate Defaulters (1981-2011)

Original rating	Defaults	Average years from original rating*	Median years from original rating	Standard deviation of years from original rating	Range
AAA	7	16.4	9.0	11.3	22.8
AA	28	15.4	16.5	7.8	25.2
A	86	12.6	10.6	7.8	27.0
BBB	185	8.0	6.6	5.7	30.7
BB	513	6.4	5.0	5.0	28.2
B	1114	4.7	3.5	3.9	26.5
CCC/C	135	2.5	1.4	3.0	17.4
Total	2068	5.8	4.1	5.2	28.9

*Or Dec. 31, 1980, whichever is later. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 11

Time To Default From All Ratings For Global Corporate Defaulters (1981-2011)

Rating path to default	Average years from rating category	Median years from rating category	Standard deviation of years from rating category
AAA	17.1	15.7	10.1
AA	14.0	14.4	8.1
A	11.0	9.6	7.4
BBB	7.6	6.0	6.2
BB	5.6	4.1	5.0
B	3.4	2.2	3.8
CCC/C	0.9	0.3	1.7
NR	4.5	2.7	4.8
Total	3.8	2.0	4.9

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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Table 12 shows the cumulative distribution of defaulters by timeline of default count based on the original rating on a firm. The first row is the rating distribution of defaults occurring within 12 months of the original rating. The second row is the distribution of the cumulative count of defaults occurring within three years of the original rating. In line with expectations, the majority (87.8%) of companies that defaulted within one year of the original rating are from the lowest rating categories of the speculative-grade universe. For example, of the 123 companies that defaulted within 12 months of having been rated, 109 were originally rated in the 'B' category ('B+', 'B', and 'B-') or lower. Only when looking at longer time frames do companies with higher original ratings surface among the defaulters. For example, of all the companies that defaulted during 1981-2011, only two entities rated 'AAA' at inception defaulted within seven years. Throughout the 31-year span, only seven companies initially rated 'AAA' have ever defaulted. These were Macy's Inc., Ally Financial Inc., Ambac Assurance Corp., Mutual Benefit Life Insurance Co., Executive Life Insurance Co. CA, Confederation Life Insurance Co., and Motors Liquidation Co. (formerly known as General Motors Corp.).

Table 13 shows the cumulative defaults over various time horizons from all ratings, which includes initial ratings (see table 12), as well as from all other ratings until reaching default. Each issuer is likely to be captured multiple times, in line with its migration from one rating to another, so the total count in table 13 is different from that in table 12. From the first row of this table, we see that 10 companies rated 'A' at any point in their lifetime defaulted within one year of receiving this rating. It is important to note that in table 13, the times to default are from the date that each entity received each unique rating in its path to default. In contrast, table 21 reports transition to default rates using the static-pool methodology, which calculates movements to default from the beginning of each static-pool year. This usually leads to shorter time frames from which to calculate default statistics. Data provided in table 13 also differs from default rates provided in table 24 owing to the use of the static-pool methodology. For more information on methodologies and definitions, please see Appendix I.

Table 12

Cumulative Defaulters By Time Horizon Among Global Corporates From Original Rating (1981-2011)

	AAA	AA	A	BBB	BB	B	CCC/C	Total
Number of issuers defaulting within:								
One year				3	11	59	50	123
Three years			6	28	124	449	98	705
Five years		2	13	68	259	761	118	1221
Seven years	2	5	27	99	346	919	126	1524
Total	7	28	86	185	513	1114	135	2068
Percent of total defaults per time frame:								
One year	0.0	0.0	0.0	2.4	8.9	48.0	40.7	
Three years	0.0	0.0	0.9	4.0	17.6	63.7	13.9	
Five years	0.0	0.2	1.1	5.6	21.2	62.3	9.7	
Seven years	0.1	0.3	1.8	6.5	22.7	60.3	8.3	
Total	0.3	1.4	4.2	8.9	24.8	53.9	6.5	

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 13

Cumulative Defaulters By Time Horizon Among Global Corporates From Rating (1981-2011)

	AAA	AA	A	BBB	BB	B	CCC/C	NR	Total
Number of issuers defaulting within:									
One year			10	66	173	885	1716	113	2,963
Three years		7	43	162	515	1950	2080	264	5,021
Five years		11	67	253	794	2549	2164	340	6,178
Seven years	2	19	93	336	978	2834	2192	391	6,845
Total	9	71	266	592	1365	3213	2227	497	8,240
Percent of total defaults per time frame:									
One year	0.0	0.0	0.3	2.2	5.8	29.9	57.9	3.8	
Three years	0.0	0.1	0.9	3.2	10.3	38.8	41.4	5.3	
Five years	0.0	0.2	1.1	4.1	12.9	41.3	35.0	5.5	
Seven years	0.0	0.3	1.4	4.9	14.3	41.4	32.0	5.7	
Total	0.1	0.9	3.2	7.2	16.6	39.0	27.0	6.0	

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Defaults are disproportionately from low rating categories, even during times of heightened stress (see table 14). Over longer time horizons, the same is true. For example, defaults of 371 companies were recorded in the five-year pool that began in January 2007, of which 89% were speculative grade on Jan. 1, 2007. (See table 15 for a list of the 37 publicly rated investment-grade defaults during this time period; three defaults that were confidentially rated are not listed.) Among nonfinancial entities, the lower the rating, the higher the number of defaults, and the lower the survival rates. Note that among financials, ratings are concentrated in investment grade, and the speculative-grade category accounts for no more than 20% of all ratings in the pools. For these sectors, defaults were clustered at the lower end of the investment-grade category in the three- and five-year horizons. Among the defaulters in 2011, only MF Global began the year rated investment grade. In addition, all but one of the defaulters that were rated at the beginning of the year originated in the 'B' and 'CCC/C' categories (see table 14).

Table 14

Defaults And Survivor Rates In The Latest One-, Three-, And Five-Year Pools

show

	--Latest one year--			--Latest three year--			--Latest five year--		
Rating	Number of	Number of	Nondefault rate (%)	Number of ratings as	Number of defaults	Nondefault rate (%)	Number of ratings as	Number of defaults	Nondefault rate (%)

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	ratings as of Jan. 1, 2011	defaults through December 2011		of Jan. 1, 2009	through December 2011		of Jan. 1, 2007	through December 2011	
Global									
AAA	51	0	100.0	73	0	100.0	84	1	98.8
AA	363	0	100.0	470	0	100.0	491	5	99.0
A	1,387	0	100.0	1,391	4	99.7	1,334	8	99.4
BBB	1,530	1	99.9	1,492	14	99.1	1,472	26	98.2
BB	982	0	100.0	965	14	98.5	1,026	68	93.4
B	1,396	21	98.5	1,189	178	85.0	1,215	218	82.1
CCC/C	138	22	84.1	189	114	39.7	107	45	57.9
Nonfinancials	13	0	100.0	14	0	100.0	16	0	100.0
AAA									
AA	93	0	100.0	132	0	100.0	132	0	100.0
A	564	0	100.0	584	0	100.0	630	0	100.0
BBB	1,032	0	100.0	981	0	100.0	1,032	8	99.2
BB	769	0	100.0	768	10	98.7	849	57	93.3
B	1,219	16	98.7	1,053	163	84.5	1,087	206	81.0
CCC/C	119	20	83.2	166	106	36.1	88	42	52.3
Financials									
AAA	38	0	100.0	59	0	100.0	68	1	98.5
AA	270	0	100.0	338	0	100.0	359	5	98.6
A	823	0	100.0	807	4	99.5	704	8	98.9
BBB	498	1	99.8	511	14	97.3	440	18	95.9
BB	213	0	100.0	197	4	98.0	177	11	93.8
B	177	5	97.2	136	15	89.0	128	12	90.6
CCC/C	19	2	89.5	23	8	65.2	19	3	84.2

Note: The totals included may differ from the counts in table 1 because defaults that are not rated at the beginning of the pool year are excluded.
Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 15

Investment-Grade Defaults In The Five-Year 2007 Static Pool

Company	Country	Industry	Default date	Next-to-last rating	Date of next-to -last rating	First rating	Date of first rating	Year of default
Aiful Corp.	Japan	Financial institutions	9/24/2009	CC	9/18/2009	BBB	10/6/2003	2009
Ambac Assurance Corp.	U.S.	Insurance	11/18/2009	CC	7/28/2009	AAA	12/31/1980	2009
Ambac Financial Group Inc.	U.S.	Insurance	11/2/2010	CC	7/28/2009	AA+	7/30/1991	2010
American Capital Ltd.	U.S.	Financial institutions	6/28/2010	CC	5/7/2010	BBB	12/18/2006	2010
AmTrust Financial Corp.	U.S.	Financial institutions	12/1/2009	NR	7/25/2008	BBB-	2/28/2006	2009
BluePoint Re Limited	Bermuda	Insurance	8/14/2008	A	6/9/2008	AA	10/25/2004	2008
Capmark Financial Group Inc.	U.S.	Financial institutions	10/26/2009	CC	9/4/2009	BBB-	3/23/2006	2009
CIT Group Inc.	U.S.	Financial institutions	8/17/2009	CC	7/16/2009	AA	12/31/1980	2009
Colonial BancGroup Inc.	U.S.	Financial institutions	8/17/2009	CC	7/30/2009	BBB-	1/17/1997	2009
Colonial Bank	U.S.	Financial institutions	8/17/2009	CCC-	7/30/2009	BBB	1/21/1997	2009
Commonwealth Land Title Insurance Co.	U.S.	Insurance	12/4/2008	BB-	11/24/2008	A-	6/25/1997	2008
Controladora Comercial Mexicana, S. A. B. de C. V.	Mexico	Consumer/service sector	10/9/2008	CC	10/8/2008	BB+	3/31/1998	2008
Downey Financial Corp.	U.S.	Financial institutions	11/24/2008	CCC-	11/21/2008	BBB-	6/7/1999	2008
Downey S&L Assn.	U.S.	Financial institutions	11/24/2008	CCC	11/21/2008	A+	12/31/1980	2008
Energy Future Holdings Corp.	U.S.	Energy and natural resources	11/16/2009	CC	10/5/2009	BBB	10/3/1997	2009
FGIC Corp.	U.S.	Insurance	8/3/2010	NR	4/22/2009	AA	1/5/2004	2010
General Growth Properties, Inc.	U.S.	Real Estate	3/17/2009	CC	12/24/2008	BBB-	6/2/1998	2009
Glitnir Bank	Iceland	Financial institutions	10/9/2008	CCC	10/7/2008	A-	3/28/2006	2008
Gulf Finance House	Bahrain	Financial institutions	2/10/2010	CC	2/2/2010	BBB-	8/7/2006	2010
Indymac Bancorp	U.S.	Financial institutions	7/14/2008	CCC	7/9/2008	BB+	10/23/2001	2008
IndyMac Bank FSB	U.S.	Financial institutions	7/14/2008	B-	7/9/2008	BBB-	9/4/1998	2008
LandAmerica Financial Group Inc.	U.S.	Insurance	11/26/2008	B-	11/24/2008	BBB-	11/19/2004	2008
Lehman Brothers Holdings Inc.	U.S.	Financial institutions	9/16/2008	A	6/2/2008	AA-	1/1/1985	2008
Lehman Brothers Inc.	U.S.	Financial institutions	9/23/2008	BB-	9/15/2008	AA	10/5/1984	2008

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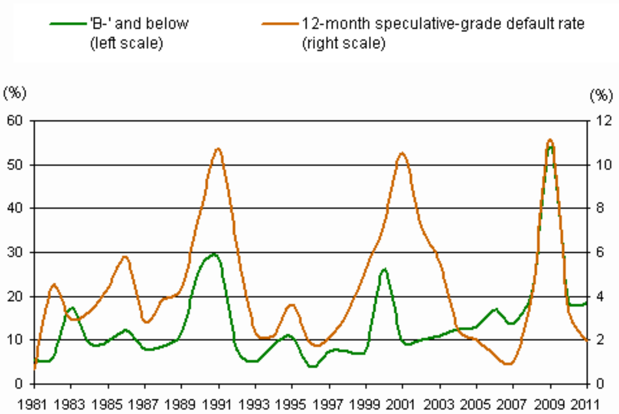
Liz Claiborne Inc.	U.S.	Consumer/service sector	4/11/2011	CC	3/11/2011	BBB	11/16/1999	2011
Mashantucket Western Pequot Tribe	U.S.	Leisure time/media	11/16/2009	CCC	8/26/2009	BBB-	9/16/1999	2009
PMI Group Inc.	U.S.	Insurance	11/28/2011	CC	8/4/2011	A+	11/6/1996	2011
PMI Mortgage Insurance Co.	U.S.	Insurance	8/22/2011	CCC-	8/4/2011	AA	3/8/1985	2011
Residential Capital LLC	U.S.	Financial institutions	6/4/2008	CC	5/2/2008	BBB-	6/9/2005	2008
South Canterbury Finance Ltd.	New Zealand	Financial institutions	8/30/2010	CC	8/20/2010	BBB-	12/17/2006	2010
Takefuji Corp.	Japan	Financial institutions	12/15/2009	CC	11/17/2009	A-	2/10/1999	2009
Technicolor S.A.	France	Consumer/service sector	5/7/2009	CC	1/29/2009	BBB+	7/24/2002	2009
The International Banking Corp.	Bahrain	Financial institutions	5/12/2009	BBB-	5/2/2006	BBB-	5/2/2006	2009
The McClatchy Co.	U.S.	Leisure time/media	6/29/2009	CC	5/22/2009	BBB-	2/8/2000	2009
Washington Mutual Bank	U.S.	Financial institutions	9/26/2008	BBB-	9/15/2008	B+	1/24/1989	2008
Washington Mutual, Inc.	U.S.	Financial institutions	9/26/2008	CCC	9/24/2008	BBB	7/17/1995	2008
YRC Worldwide Inc.	U.S.	Transportation	1/4/2010	CC	11/2/2009	BBB-	11/19/2003	2010

Excludes confidentially rated defaults. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Since 1981, the 'B' rating category ('B+', 'B', and 'B-') has accounted for 1,114 defaulters (53.9% of the total), well more than double the number of entities rated 'BB'--the nearest rating category (see tables 10 and 12). Given the historical track record, monitoring the movement in new rating patterns could prove useful in anticipating future default activity based on the notion that years characterized by high numbers of new ratings of 'B-' or lower will likely be followed by increased default risk. Chart 17 plots the ratio of all new ratings of 'B-' or lower in the U.S. to total speculative-grade ratings against the year-end U.S. speculative-grade default rate. As coincident indicators, broad movements in the two series generally mirror each other throughout most of their shared history--uncannily so in the most recent three years.

Chart 17

Origination Trends And Default Rate: U.S. And Tax Havens



U.S. and tax havens include the U.S., Bermuda, and Cayman Islands. Ratings 'B-' and lower calculated as a share of total speculative grade. Data through Dec. 31, 2011. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Industry Variations

Alongside a decrease in the number of defaults in 2011 relative to the previous year, the percentage of defaulters from the financial sector has also declined. In 2011, financial defaults accounted for 15.1% of total defaults globally, which is considerably less than the 21% share in 2010. Of the eight financial entities that defaulted in 2011, four were from New Zealand, and of these, one was placed in receivership and another under regulatory directive. These defaulters, however, were small in terms of affected debt. In fact, including all financial companies, the sector only accounted for 4.6% of the total, compared with 9.4% in 2010 and more than half of the 2008 amount.

Over the long term, cyclicality has been more pronounced in nonfinancial sectors than in financial sectors, which is to be expected in light of the differences in their rating profiles (see chart 18). Financial companies were more likely to possess an initial rating in the investment-grade category, while nonfinancials companies were more likely to have initial ratings in the speculative-grade domain. Over the 31-year period this study covers, 74.8% of financials had an initial investment-grade rating, while only 36.3% of nonfinancials did. This helps to explain the resemblance between the annual default rates of nonfinancial entities and those of the speculative-grade universe as a whole. This certainly contributes to the vast differences between cumulative default rates across financial and nonfinancial sectors (see

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table 16). For example, at the end of 2011, the one-year default rate among all financial entities was 0.39%, compared with 0.95% for all nonfinancials. The gap persists and even expands over longer-term horizons, such as three years and 10 years (see chart 19).

Table 16

Cumulative Global Corporate Default Rates By Sector (%)

Sector	2011	2010	Average (1981-2011)	Median	Standard deviation	Minimum	Maximum
Financial institutions							
One year	0.41	0.92	0.66	0.28	0.75	0.00	2.42
Three years	2.99	3.88	1.97	1.50	1.76	0.00	6.34
10 years	3.06	4.21	4.94	4.11	2.64	1.59	10.00
Insurance							
One year	0.37	0.25	0.64	0.34	1.08	0.00	5.13
Three year	0.96	1.12	1.97	1.22	1.89	0.16	7.69
10 years	3.17	3.20	6.27	5.02	3.42	3.17	16.13
All financials							
One year	0.39	0.65	0.62	0.43	0.56	0.00	1.87
Three years	2.17	2.78	1.91	1.87	1.29	0.18	4.98
10 years	3.11	3.80	5.35	4.82	2.27	2.39	9.07
All nonfinancials							
One year	0.95	1.43	1.84	1.34	1.41	0.16	5.54
Three years	7.54	8.39	5.29	4.02	3.12	1.82	12.42
10 years	13.49	17.82	11.88	11.21	3.43	6.95	19.34

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 18

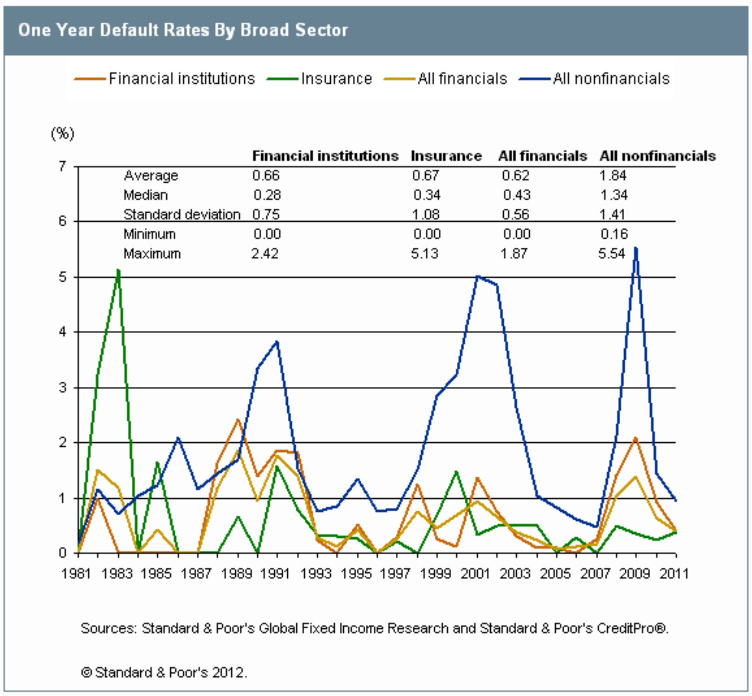

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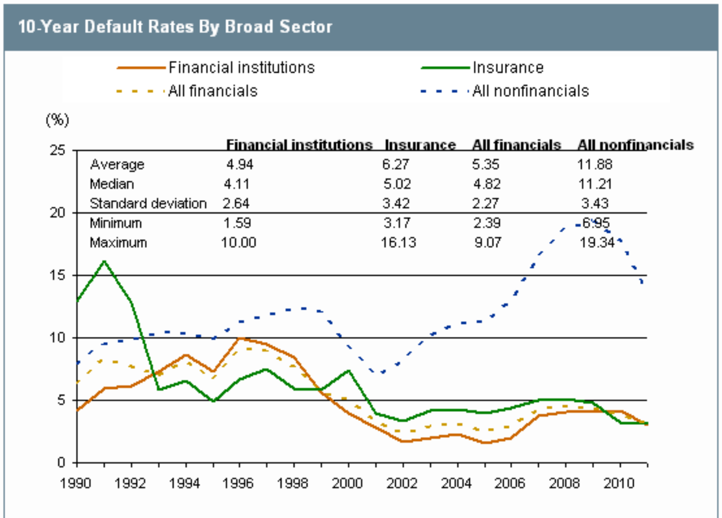
Chart 19



Source: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Of the 2,068 defaults recorded globally over the long term, six sectors displayed an average time to default that is lower than the overall average of 5.8 years. These sectors are energy and natural resources, financial institutions, high technology, leisure time/media, real estate, and telecommunications (see table 17). Using the median rather than the mean adds the transportation sector into the mix.

Table 17

Time To Default From Original Rating By Industry (%)

	Median original rating (defaulters)	Median original rating (industry)	No. of defaults	Average years from original rating*	Median years from original rating	Standard deviation of years from original rating	Range
Aerospace/automotive/capital goods/metal	B+	BB-	331	6.3	4.5	5.6	28.2
Consumer/service sector	B+	BB-	398	6.4	4.8	5.4	26.6
Energy and natural resources	B+	BB-	124	4.1	3.0	3.8	22.6
Financial institutions	BB-	BBB+	164	5.2	3.6	5.6	28.6
Forest and building products/homebuilders	B+	BB-	133	6.6	4.7	5.4	27.8
Health care / chemicals	B+	BB-	128	5.8	4.1	4.9	27.4
High technology/computers/office equipment	B+	B+	67	5.1	3.7	4.7	28.3
Insurance	BBB+	A	67	7.8	6.6	5.9	28.6
Leisure time/media	B+	B+	292	5.5	4.0	4.7	28.4
Real estate	BB-	BBB-	35	3.9	3.1	3.0	10.5
Telecommunications	B	B+	152	4.0	3.2	3.0	21.4
Transportation	B+	BB+	117	6.2	3.8	6.4	30.9
Utility	BBB-	BBB+	60	6.0	4.1	5.9	24.2
Total	B+	BB+	2,068	5.8	4.1	5.2	30.9

*Or Dec. 31, 1980, whichever is later. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 18

Time To Default From All Ratings By Industry (%)

	No. of defaults	Average years to default	Median years to default	Standard deviation of years to default
Aerospace/automotive/capital goods/metal	331	3.5	1.3	5.1
Consumer/service sector	398	3.3	1.5	4.6
Energy and natural resources	124	2.1	0.8	3.4
Financial institutions	164	2.7	0.7	4.8
Forest and building products/homebuilders	133	3.2	1.3	4.5
Health care/chemicals	128	2.8	1.0	4.2
High technology/computers/office equipment	67	3.5	1.5	5.1
Insurance	67	3.4	1.6	4.6
Leisure time/media	292	2.8	1.0	4.3

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Real estate	35	1.6	0.8	2.3
Telecommunications	152	1.8	0.6	2.9
Transportation	117	4.2	1.4	6.1
Utility	60	2.8	0.6	4.9
Total	2,068	3.0	2.0	4.9

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Default rates by industry in 2011 were generally lower relative to their 2010 levels and to their long-term averages (see table 19). By industry, only the forest and building products/homebuilders, leisure time/media, and transportation sectors had default rates in 2011 that were higher than 2%. And only one other--the consumer/service sector--breached 1%. Expect for consumer/service, these industries often have the highest annual default rates. This is particularly true in leisure time/media and forest and building products/homebuilders, given their reliance on the economic health of consumers, which has been declining in recent years. For the second year in a row, the high technology/computers/office equipment sector had a default rate of zero. The utility and telecommunications sectors also survived 2011 without a single incidence of default. When comparing default rates across sectors, it is important to note some key differences between the various industries. Some of the variation in default rates between sectors stems from sample size differences as well as differentiation in the rating mix across industries. For example, the leisure/media sector has a much higher representation of speculative-grade ratings than the financial institutions or insurance sectors (see chart 20).

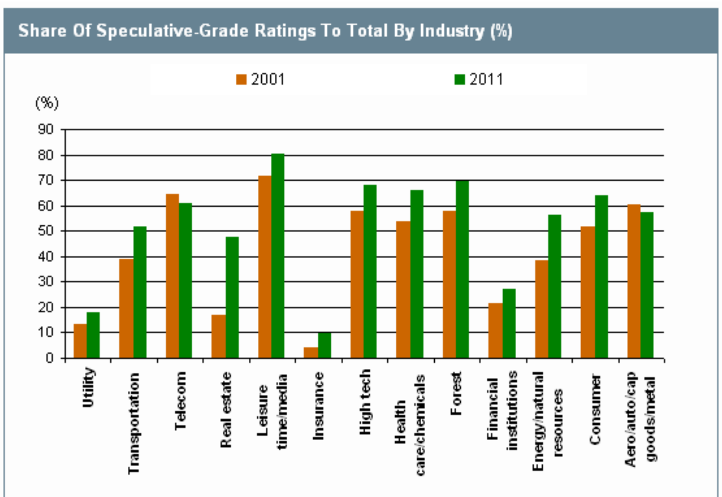
Table 19

Global Corporate Default Rates By Industry (%)

	2011	2010	Weighted average (1981-2011)	Median	Standard deviation	Minimum	Maximum
Aerospace/automotive/capital goods/metal	0.42	1.34	2.48	1.34	2.18	0.00	9.65
Consumer/service sector	1.51	1.78	2.45	1.78	1.69	0.00	6.34
Energy and natural resources	0.98	1.09	1.73	1.09	2.19	0.00	10.00
Financial institutions	0.41	0.92	0.69	0.28	0.75	0.00	2.42
Forest and building products/homebuilders	2.63	2.94	2.73	1.41	3.05	0.00	14.21
Health care/chemicals	0.53	1.45	1.60	0.85	1.40	0.00	4.67
High technology/computers/office equipment	0.00	0.00	1.31	1.00	1.59	0.00	4.91
Insurance	0.37	0.25	0.41	0.34	1.08	0.00	5.13
Leisure time/media	2.06	4.76	3.62	2.06	3.51	0.00	16.62
Real estate	0.82	0.56	0.87	0.00	2.64	0.00	9.68
Telecommunications	0.00	0.52	2.99	0.50	4.23	0.00	18.60
Transportation	2.82	1.60	2.12	1.79	1.71	0.00	6.06
Utility	0.00	0.17	0.43	0.00	0.81	0.00	4.23

Includes investment-grade and speculative-grade entities. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 20



Telecom--Telecommunications. High tech--High technology/computers/office equipment. Forest--Forest and building products/homebuilders. Cons--Consumer/service sector. Aero/auto/cap goods/metal--Aerospace/automotive/capital goods/metal. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Hefty Growth In Speculative-Grade Ratings

History suggests that growth in speculative-grade ratings is usually a precursor to a wave of defaults. The surge in speculative-grade originations beginning in 2002 in the U.S.--where the high-yield market has the most depth--supports this notion (see chart 23). By contrast, speculative-grade rating originations in Europe appear more subdued, but much of the leveraged activity migrated to the private credit estimate market, which is not included in this study or the CreditPro® database (see chart 24). As default rates have been falling

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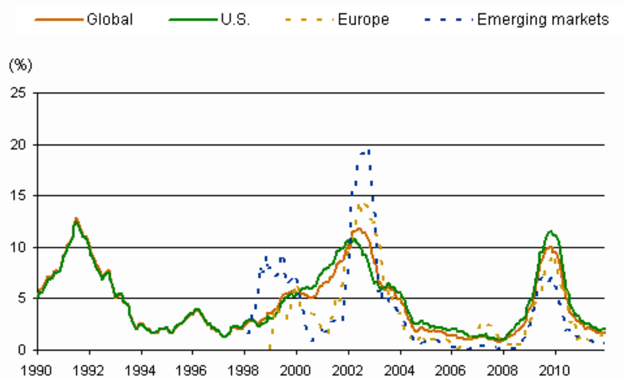
around the globe, another increase in the proportion of speculative-grade issuers has begun, particularly in the U.S., where 51.5% of issuers are rated speculative grade as of December 2011.

This most recent default cycle was different than the previous two, which peaked in mid-1991 and mid-2002. In this latest cycle, default activity was centered on the U.S. It was also a shorter cycle when measured from the most recent trough, at the start of 2008, to the end of 2011 (see charts 22-24). This more abbreviated time frame is most likely the result of the massive interventions by central banks and governments, which were far less of a factor in the previous two cycles. On a trailing-12-month basis, the global speculative-grade default rate peaked at 10.1% in November 2009 (see chart 21). As we're past the low point for corporate financial markets, risk appetite has increased, as demonstrated by an increase in the share of new issuers rated speculative grade over the last two years, to 72.5% in 2011 and an all-time high of 79% in 2010. In addition, the total number of issuers receiving initial ratings was at its third-highest level (712) in 2011, further emphasizing a continued positive corporate credit outlook.

Chart 21

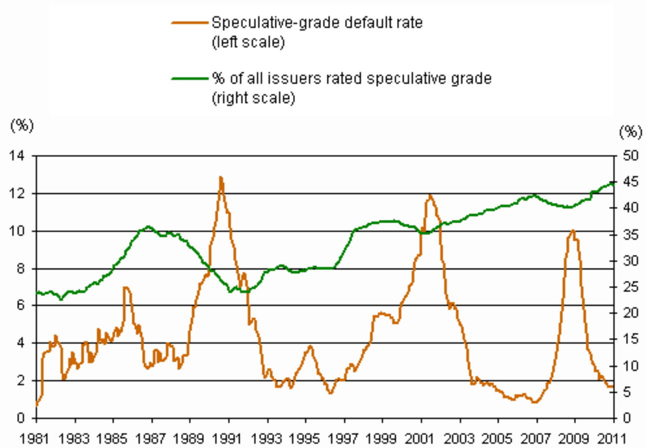
Trailing-12-Month Corporate Speculative-Grade Default Rate



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 22

Global Corporate Speculative-Grade Default Rate Versus Prevalence Of Speculative-Grade Issuers



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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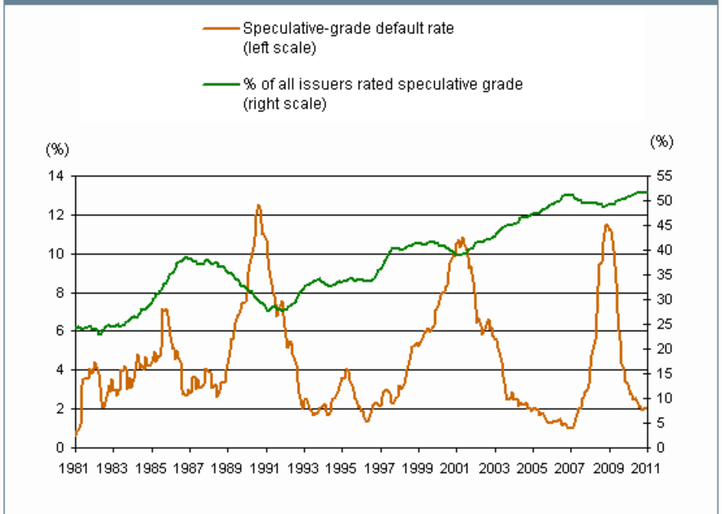
Chart 23

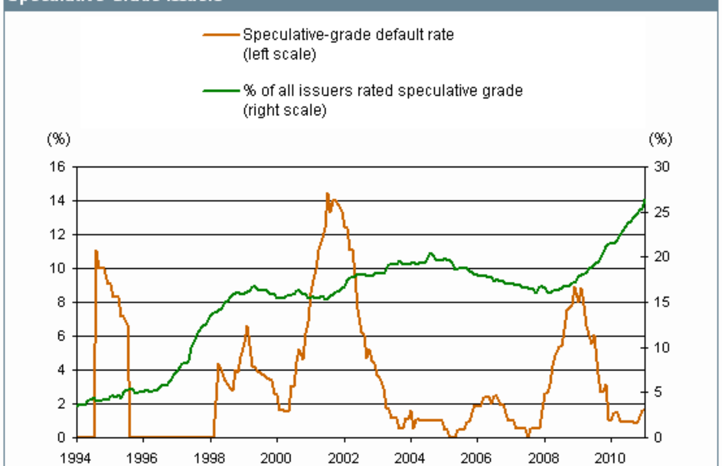
U.S. Corporate Speculative-Grade Default Rate Versus Prevalence Of Speculative-Grade Issuers



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 24

European Corporate Speculative-Grade Default Rate Versus Prevalence Of Speculative-Grade Issuers



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Transition Tables And Cumulative Default Rates

Barring the 2008 default of Lehman Brothers, the downgrade of the U.S. government on Aug. 5, 2011, had more significant repercussions for the profile of corporate issuers than any other event in recent years. With the downgrade of the U.S. to 'AA+' from 'AAA', a large number of 'AAA' rated financial institutions with ratings implicitly tied to that on the sovereign experienced downgrades to 'AA+' shortly after. Nearly as many insurance groups were downgraded to 'AA+' from 'AAA', given their large holdings of U.S. Treasuries. As a result of these downgrades, the 'AAA' stability rate for 2011 fell to 49% globally and to a meager 14.3% in the U.S. In fact, of all 'AAA' downgrades in 2011, only one was from outside the U.S.

The global pool of 'AAA' rated corporate entities (including insurance companies and financial institutions) is now roughly one-quarter of the size it was at the beginning of 2007. The economic downturn and financial crisis that began in the second half of 2007 have caused a large number of downgrades, particularly in the U.S. financial sector. Within the U.S., only four corporate entities are rated 'AAA', none of which are financial institutions or insurance companies. In contrast, 89% of 'AAA' rated companies in the U.S. at the start of 2007 belonged to one of these two sectors. In Europe, changes to our bank criteria in November produced a large number of downgrades within the 'AA' rating category (see table 20).

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Barring the large number of downgrades from the highest rating categories in 2011, an analysis of transition rates over the four quarters ended December 2011 suggests that ratings behavior continues to exhibit consistency with long-term trends, showing a negative correspondence between ratings and observed frequency of default. Investment-grade-rated issuers tend to exhibit greater rating stability (as measured by the frequency of rating transition) than their speculative-grade counterparts (see table 20). For instance, 86.7% of issuers rated 'A' at the beginning of 2011 were still rated 'A' by Dec. 31, 2011, whereas the comparable share for issuers rated 'B' was only 76.3%. The same relationship holds when we analyze the transition rates separately for the U.S., Europe, and the emerging markets.

Over the long term (1981-2011) heightened ratings stability is broadly consistent with higher ratings (see table 21). A key observation when analyzing transition matrices that present averages computed over multiple static pools is that the standard deviations associated with each transition point in the matrix are large relative to the averages (outside of stability rates). This will also be applicable within the average cumulative default rate tables presented in this study. This reflects the significant variability across multiple static pools.

Table 20

2011 One-Year Corporate Transition Rates By Region (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
Global									
AAA	49.02	47.06	0.00	0.00	0.00	0.00	0.00	0.00	3.92
AA	0.00	80.99	12.67	0.83	0.00	0.28	0.00	0.00	5.23
A	0.00	1.80	86.66	6.78	0.50	0.00	0.00	0.00	4.25
BBB	0.00	0.00	2.68	89.61	2.75	0.33	0.07	0.07	4.51
BB	0.00	0.00	0.00	5.60	79.33	4.68	0.51	0.00	9.88
B	0.00	0.00	0.00	0.14	6.59	76.29	3.44	1.50	12.03
CCC/C	0.00	0.00	0.00	0.00	0.00	23.19	47.83	15.94	13.04
U.S.									
AAA	14.29	82.14	0.00	0.00	0.00	0.00	0.00	0.00	3.57
AA	0.00	83.33	11.36	0.76	0.00	0.00	0.00	0.00	4.55
A	0.00	0.92	90.57	4.99	0.18	0.00	0.00	0.00	3.33
BBB	0.00	0.00	2.21	92.54	2.07	0.00	0.14	0.14	2.90
BB	0.00	0.00	0.00	2.94	83.23	5.24	0.00	0.00	8.60
B	0.00	0.00	0.00	0.22	5.38	78.16	3.70	1.57	10.97
CCC/C	0.00	0.00	0.00	0.00	0.00	23.16	47.37	15.79	13.68
Europe									
AAA	84.62	7.69	0.00	0.00	0.00	0.00	0.00	0.00	7.69
AA	0.00	77.78	16.30	1.48	0.00	0.00	0.00	0.00	4.44
A	0.00	2.94	80.04	10.92	1.26	0.00	0.00	0.00	4.83
BBB	0.00	0.00	2.79	85.37	5.23	1.74	0.00	0.00	4.88
BB	0.00	0.00	0.00	10.09	70.64	1.83	4.59	0.00	12.84
B	0.00	0.00	0.00	0.00	13.28	64.06	5.47	1.56	15.63
CCC/C	0.00	0.00	0.00	0.00	0.00	30.77	30.77	15.38	23.08
Emerging markets									
AAA	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA	0.00	94.44	5.56	0.00	0.00	0.00	0.00	0.00	0.00
A	0.00	2.40	86.23	7.78	0.00	0.00	0.00	0.00	3.59
BBB	0.00	0.00	3.53	85.59	2.35	0.29	0.00	0.00	8.24
BB	0.00	0.00	0.00	7.85	78.25	4.23	0.00	0.00	9.67
B	0.00	0.00	0.00	0.00	7.34	75.23	2.45	0.61	14.37
CCC/C	0.00	0.00	0.00	0.00	0.00	24.00	60.00	8.00	8.00

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

This study--in line with previous default studies--confirms that over the long term (1981-2011), higher ratings are more stable than lower ratings. 'AAA' rated issuers were still rated 'AAA' one year later 87.19% of the time, and 'CCC'/'C' ratings remained 'CCC'/'C' 43.93% of the time. These long-term relationships do not change even when default rates are calculated over longer time horizons (see table 21) or are broken out by region (see table 22). In contrast, the relationship is slightly more discontinuous when we examine the rating transitions across modifiers (i.e., a plus or minus after a rating), but these variations are likely a result of sample size variations, and we do not consider them significant (see table 23). For example, 'AA+' rated issuers were still rated 'AA+' one year later 76.2% of the time, and 'AA' rated issuers were still rated 'AA' one year later 79.8% of the time.

Table 21

Global Corporate Average Transition Rates (1981-2011) (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
One-year									
AAA	87.19	8.69	0.54	0.05	0.08	0.03	0.05	0.00	3.37
	(9.11)	(9.10)	(0.87)	(0.31)	(0.25)	(0.20)	(0.40)	(0.00)	(2.58)
AA	0.56	86.32	8.30	0.54	0.06	0.08	0.02	0.02	4.09
	(0.55)	(4.94)	(4.01)	(0.73)	(0.25)	(0.25)	(0.07)	(0.07)	(1.92)
A	0.04	1.91	87.27	5.44	0.38	0.16	0.02	0.08	4.72

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	(0.13)	(1.15)	(3.49)	(2.10)	(0.49)	(0.36)	(0.07)	(0.11)	(1.92)
BBB	0.01	0.12	3.64	84.87	3.91	0.64	0.15	0.24	6.42
	(0.07)	(0.23)	(2.31)	(4.64)	(1.84)	(1.03)	(0.24)	(0.27)	(1.82)
BB	0.02	0.04	0.16	5.24	75.87	7.19	0.75	0.90	9.84
	(0.06)	(0.16)	(0.39)	(2.37)	(4.97)	(4.70)	(0.92)	(1.05)	(2.85)
B	0.00	0.04	0.13	0.22	5.57	73.42	4.42	4.48	11.72
	(0.00)	(0.13)	(0.38)	(0.34)	(2.52)	(5.30)	(2.57)	(3.32)	(3.02)
CCC/C	0.00	0.00	0.17	0.26	0.78	13.67	43.93	26.82	14.37
	(0.00)	(0.00)	(0.71)	(1.02)	(1.30)	(8.59)	(12.79)	(12.68)	(7.32)
Three-year									
AAA	66.82	19.93	2.42	0.33	0.17	0.08	0.11	0.14	9.99
	(11.61)	(11.67)	(1.67)	(0.83)	(0.45)	(0.35)	(0.51)	(0.39)	(5.50)
AA	1.29	65.24	18.95	2.24	0.36	0.27	0.03	0.15	11.47
	(0.79)	(8.34)	(5.83)	(1.41)	(0.66)	(0.53)	(0.08)	(0.19)	(4.32)
A	0.08	4.42	67.45	11.90	1.40	0.57	0.12	0.33	13.74
	(0.11)	(2.38)	(5.96)	(2.83)	(1.14)	(0.82)	(0.16)	(0.26)	(3.69)
BBB	0.03	0.38	8.67	62.12	7.36	2.07	0.36	1.19	17.83
	(0.10)	(0.54)	(4.11)	(7.92)	(2.67)	(1.76)	(0.50)	(0.86)	(3.40)
BB	0.01	0.07	0.65	11.17	44.28	12.13	1.35	4.97	25.36
	(0.09)	(0.23)	(1.10)	(4.30)	(5.86)	(3.83)	(1.09)	(3.44)	(4.01)
B	0.01	0.04	0.32	1.00	10.71	39.49	4.54	15.25	28.63
	(0.12)	(0.16)	(0.80)	(0.99)	(3.64)	(6.30)	(2.40)	(6.82)	(6.03)
CCC/C	0.00	0.00	0.26	0.88	1.86	15.18	11.62	42.69	27.52
	(0.00)	(0.00)	(0.86)	(2.34)	(3.41)	(7.59)	(11.50)	(14.23)	(11.60)
Five-year									
AAA	52.33	24.52	4.96	0.87	0.17	0.15	0.09	0.35	16.56
	(9.54)	(9.66)	(2.63)	(1.80)	(0.44)	(0.46)	(0.33)	(0.61)	(6.65)
AA	1.62	50.95	24.17	3.94	0.59	0.41	0.05	0.35	17.91
	(0.92)	(6.79)	(4.64)	(1.79)	(0.71)	(0.72)	(0.12)	(0.38)	(4.86)
A	0.10	5.55	54.06	15.07	2.19	0.85	0.18	0.67	21.33
	(0.11)	(2.58)	(6.84)	(2.33)	(1.30)	(1.15)	(0.22)	(0.43)	(4.15)
BBB	0.04	0.65	10.60	48.20	7.86	2.77	0.44	2.39	27.06
	(0.11)	(0.68)	(4.34)	(7.93)	(2.47)	(1.83)	(0.58)	(1.30)	(4.36)
BB	0.01	0.09	1.30	12.49	28.25	11.25	1.42	9.16	36.03
	(0.08)	(0.28)	(1.27)	(4.09)	(5.24)	(3.20)	(1.47)	(4.61)	(4.21)
B	0.02	0.04	0.41	1.93	10.77	22.87	2.93	21.41	39.62
	(0.27)	(0.14)	(1.18)	(1.55)	(2.85)	(5.81)	(1.42)	(7.97)	(6.27)
CCC/C	0.00	0.00	0.24	0.91	3.16	12.38	3.28	45.93	34.10
	(0.00)	(0.00)	(0.84)	(4.15)	(3.22)	(5.56)	(7.92)	(13.97)	(12.18)
Seven-year									
AAA	41.59	26.98	7.35	1.68	0.21	0.12	0.12	0.49	21.44
	(7.09)	(7.21)	(2.40)	(2.15)	(0.50)	(0.40)	(0.35)	(0.75)	(7.09)
AA	1.69	40.17	27.20	5.21	0.78	0.38	0.04	0.52	24.01
	(1.03)	(4.70)	(3.76)	(1.62)	(0.72)	(0.59)	(0.10)	(0.55)	(4.70)
A	0.10	5.80	44.69	16.77	2.77	1.01	0.17	1.13	27.56
	(0.14)	(2.08)	(6.30)	(1.78)	(1.40)	(1.25)	(0.23)	(0.54)	(3.69)
BBB	0.05	0.90	10.95	39.19	7.69	2.87	0.41	3.65	34.29
	(0.17)	(0.56)	(3.85)	(6.29)	(0.91)	(1.30)	(0.52)	(1.60)	(3.56)
BB	0.00	0.09	1.76	12.19	19.58	9.72	1.10	12.99	42.57
	(0.00)	(0.30)	(1.38)	(4.39)	(4.52)	(2.77)	(0.99)	(4.93)	(3.76)
B	0.01	0.03	0.60	2.42	8.92	13.77	1.78	26.29	46.18
	(0.23)	(0.15)	(1.01)	(2.00)	(2.32)	(3.58)	(0.93)	(7.48)	(6.02)
CCC/C	0.00	0.00	0.42	1.32	3.62	8.36	1.46	48.82	36.00
	(0.00)	(0.00)	(0.93)	(4.69)	(2.40)	(4.23)	(4.45)	(13.14)	(11.04)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 22

Average One-Year Corporate Transition Rates (1981-2011) (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
U.S.									
AAA	87.41	8.42	0.57	0.04	0.12	0.04	0.04	0.00	3.35
	(14.92)	(15.03)	(1.22)	(0.19)	(0.36)	(0.32)	(0.32)	(0.00)	(2.63)
AA	0.57	86.28	8.05	0.65	0.09	0.13	0.04	0.04	4.16
	(0.52)	(6.51)	(4.83)	(0.89)	(0.23)	(0.30)	(0.11)	(0.18)	(2.37)
A	0.05	1.80	87.26	5.63	0.46	0.19	0.03	0.08	4.49

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	(0.14)	(1.28)	(3.74)	(2.41)	(0.54)	(0.36)	(0.11)	(0.17)	(1.83)
BBB	0.01	0.14	3.58	85.03	4.23	0.72	0.13	0.27	5.89
	(0.07)	(0.22)	(2.42)	(4.91)	(1.71)	(1.08)	(0.19)	(0.31)	(1.93)
BB	0.03	0.06	0.20	5.13	75.85	8.12	0.68	0.96	8.98
	(0.08)	(0.17)	(0.38)	(2.62)	(5.28)	(4.80)	(0.84)	(1.00)	(2.86)
B	0.00	0.05	0.15	0.24	5.02	74.54	4.65	4.59	10.76
	(0.00)	(0.13)	(0.38)	(0.35)	(2.49)	(5.30)	(2.72)	(3.30)	(3.06)
CCC/C	0.00	0.00	0.23	0.35	0.87	12.25	45.06	27.58	13.65
	(0.00)	(0.00)	(0.75)	(1.08)	(1.42)	(8.44)	(12.39)	(12.90)	(6.84)
Europe									
AAA	84.14	9.47	0.66	0.22	0.00	0.00	0.22	0.00	5.29
	(5.87)	(5.87)	(1.71)	(1.67)	(0.00)	(0.00)	(1.25)	(0.00)	(4.66)
AA	0.27	84.46	10.73	0.50	0.00	0.00	0.00	0.00	4.05
	(0.44)	(6.33)	(5.76)	(0.80)	(0.00)	(0.00)	(0.00)	(0.00)	(1.99)
A	0.02	2.36	86.36	5.77	0.27	0.02	0.00	0.05	5.15
	(0.05)	(1.35)	(3.78)	(2.80)	(0.38)	(0.08)	(0.00)	(0.11)	(2.05)
BBB	0.00	0.12	4.62	83.22	3.69	0.57	0.15	0.12	7.50
	(0.00)	(0.23)	(2.28)	(3.63)	(2.74)	(0.61)	(0.36)	(0.28)	(3.89)
BB	0.00	0.00	0.16	5.11	70.85	7.75	0.72	0.64	14.78
	(0.00)	(0.00)	(2.27)	(2.98)	(6.97)	(4.19)	(1.22)	(1.17)	(5.93)
B	0.00	0.00	0.10	0.30	7.61	65.07	4.90	3.70	18.32
	(0.00)	(0.00)	(0.43)	(0.58)	(5.02)	(7.41)	(3.47)	(5.19)	(7.64)
CCC/C	0.00	0.00	0.00	0.00	0.00	16.33	26.53	34.69	22.45
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(13.87)	(19.68)	(24.30)	(26.61)
Emerging markets									
AAA	86.96	4.35	0.00	0.00	0.00	0.00	0.00	0.00	8.70
	(22.13)	(11.38)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(17.18)
AA	2.53	84.81	8.23	0.63	0.00	0.00	0.00	0.00	3.80
	(5.88)	(15.66)	(11.73)	(3.13)	(0.00)	(0.00)	(0.00)	(0.00)	(6.89)
A	0.00	1.59	89.61	5.08	0.38	0.53	0.00	0.08	2.73
	(0.00)	(1.77)	(8.19)	(6.49)	(1.20)	(2.35)	(0.00)	(0.13)	(1.78)
BBB	0.00	0.04	3.40	85.58	3.68	0.74	0.35	0.21	5.99
	(0.00)	(0.11)	(3.34)	(7.20)	(5.57)	(2.00)	(1.68)	(0.63)	(2.84)
BB	0.00	0.00	0.03	5.30	78.40	4.30	1.09	0.97	9.91
	(0.00)	(0.00)	(0.16)	(3.08)	(6.67)	(2.80)	(3.59)	(1.72)	(4.02)
B	0.00	0.00	0.00	0.16	8.05	70.92	2.79	3.41	14.66
	(0.00)	(0.00)	(0.00)	(0.43)	(4.57)	(6.75)	(3.64)	(5.23)	(5.83)
CCC/C	0.00	0.00	0.00	0.00	0.51	20.31	45.50	18.77	14.91
	(0.00)	(0.00)	(0.00)	(0.00)	(0.82)	(13.50)	(23.32)	(16.63)	(24.56)

Note: Numbers in parentheses are standard deviations. For Europe and emerging markets, calculations are for 1996-2011 because of sample size considerations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 23

Average One-Year Transition Rates For Global Corporates By Rating Modifier (1981-2011) (%)

From/to	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC	D	NR
AAA	87.19	5.31	2.70	0.67	0.16	0.24	0.13	0.00	0.05	0.00	0.03	0.05	0.00	0.00	0.03	0.00	0.05	0.00	3.37
	(9.11)	(8.68)	(3.34)	(0.98)	(0.50)	(0.57)	(0.33)	(0.00)	(0.31)	(0.00)	(0.19)	(0.17)	(0.00)	(0.00)	(0.20)	(0.00)	(0.40)	(0.00)	(2.58)
AA+	2.57	76.20	11.49	4.20	0.88	0.64	0.29	0.12	0.12	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.44
	(4.76)	(11.41)	(8.53)	(4.62)	(2.77)	(0.99)	(0.63)	(0.40)	(0.82)	(0.19)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(3.18)
AA	0.46	1.29	79.84	8.70	3.01	1.38	0.42	0.44	0.14	0.09	0.05	0.04	0.02	0.02	0.00	0.02	0.05	0.02	4.01
	(0.52)	(1.62)	(9.26)	(7.05)	(2.51)	(1.25)	(0.64)	(0.85)	(0.35)	(0.24)	(0.16)	(0.12)	(0.11)	(0.15)	(0.00)	(0.09)	(0.15)	(0.08)	(2.51)
AA-	0.05	0.12	4.20	76.88	10.19	2.78	0.69	0.28	0.14	0.07	0.03	0.00	0.00	0.03	0.10	0.02	0.00	0.03	4.36
	(0.17)	(0.28)	(4.04)	(6.57)	(4.48)	(3.61)	(0.87)	(0.66)	(0.38)	(0.20)	(0.44)	(0.00)	(0.00)	(0.22)	(0.59)	(0.06)	(0.00)	(0.10)	(2.21)
A+	0.00	0.10	0.56	4.59	77.15	9.03	2.47	0.72	0.40	0.09	0.09	0.12	0.01	0.09	0.04	0.01	0.00	0.06	4.46
	(0.00)	(0.21)	(0.98)	(2.72)	(5.37)	(3.05)	(1.57)	(0.73)	(0.46)	(0.24)	(0.19)	(0.35)	(0.05)	(0.23)	(0.18)	(0.05)	(0.00)	(0.15)	(2.13)
A	0.05	0.05	0.27	0.53	5.03	77.59	7.00	2.71	1.14	0.28	0.14	0.14	0.10	0.12	0.03	0.01	0.02	0.08	4.71
	(0.16)	(0.15)	(0.58)	(0.51)	(1.79)	(4.58)	(3.01)	(1.76)	(1.01)	(0.37)	(0.26)	(0.36)	(0.40)	(0.43)	(0.10)	(0.04)	(0.06)	(0.14)	(2.32)
A-	0.06	0.01	0.10	0.19	0.58	6.71	75.91	7.55	2.39	0.73	0.20	0.17	0.15	0.13	0.03	0.01	0.04	0.08	4.96
	(0.34)	(0.05)	(0.26)	(0.43)	(0.84)	(3.79)	(6.01)	(3.03)	(1.48)	(0.80)	(0.59)	(0.53)	(0.30)	(0.43)	(0.08)	(0.14)	(0.15)	(0.20)	(1.95)
BBB+	0.00	0.01	0.07	0.08	0.29	1.01	6.96	73.46	8.78	2.00	0.46	0.39	0.16	0.26	0.14	0.02	0.09	0.15	5.67
	(0.00)	(0.05)	(0.26)	(0.29)	(0.75)	(1.74)	(3.66)	(7.12)	(3.50)	(2.02)	(0.87)	(0.62)	(0.32)	(0.62)	(0.39)	(0.05)	(0.27)	(0.32)	(2.56)
BBB	0.01	0.01	0.06	0.04	0.16	0.45	1.21	7.18	74.54	6.21	1.57	0.82	0.37	0.30	0.18	0.05	0.08	0.21	6.54
	(0.12)	(0.13)	(0.20)	(0.21)	(0.30)	(1.03)	(1.38)	(3.10)	(5.31)	(2.24)	(1.38)	(0.77)	(0.76)	(0.67)	(0.67)	(0.09)	(0.13)	(0.35)	(2.49)
BBB-	0.01	0.01	0.01	0.07	0.07	0.25	0.36	1.31	8.84	71.33	5.39	2.48	1.00	0.52	0.33	0.21	0.30	0.37	7.13
	(0.10)	(0.05)	(0.04)	(0.34)	(0.26)	(0.73)	(1.05)	(1.88)	(3.65)	(7.56)	(3.09)	(2.25)	(1.21)	(1.48)	(0.78)	(0.79)	(0.63)	(0.46)	(2.73)
BB+	0.07	0.00	0.00	0.05	0.02	0.14	0.09	0.62	2.25	11.94	62.57	6.37	3.20	1.24	0.81	0.18	0.55	0.51	9.39

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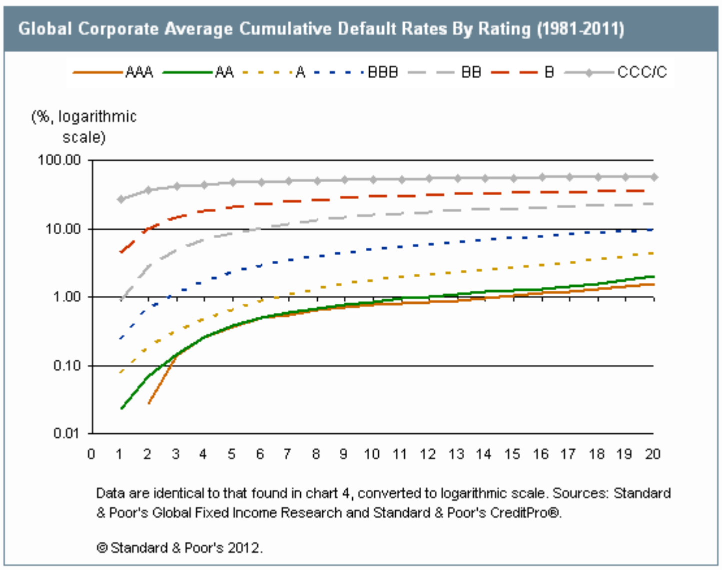
	(0.26)	(0.00)	(0.00)	(0.14)	(0.09)	(0.90)	(0.37)	(1.17)	(2.59)	(5.44)	(5.71)	(2.98)	(2.64)	(2.72)	(2.82)	(0.46)	(1.31)	(0.94)	(3.68)
BB	0.00	0.00	0.05	0.02	0.00	0.09	0.07	0.23	0.72	2.48	9.19	64.00	7.63	2.54	1.31	0.47	0.76	0.76	9.68
	(0.00)	(0.00)	(0.38)	(0.06)	(0.00)	(0.70)	(0.39)	(0.69)	(1.23)	(3.20)	(4.66)	(6.78)	(3.60)	(1.77)	(1.45)	(0.82)	(1.21)	(0.84)	(3.42)
BB-	0.00	0.00	0.00	0.01	0.01	0.01	0.07	0.15	0.30	0.47	2.06	8.74	63.51	8.25	3.14	0.95	0.86	1.23	10.24
	(0.00)	(0.00)	(0.00)	(0.16)	(0.12)	(0.10)	(0.43)	(0.36)	(0.68)	(0.88)	(2.43)	(4.44)	(7.59)	(4.99)	(1.89)	(1.21)	(1.19)	(1.78)	(3.34)
B+	0.00	0.01	0.00	0.04	0.00	0.04	0.08	0.05	0.06	0.09	0.35	1.58	7.31	64.84	7.63	2.61	1.89	2.50	10.89
	(0.00)	(0.08)	(0.00)	(0.19)	(0.00)	(0.10)	(0.30)	(0.19)	(0.27)	(0.25)	(0.43)	(1.42)	(3.54)	(8.46)	(3.32)	(1.44)	(1.63)	(2.13)	(3.65)
B	0.00	0.00	0.02	0.02	0.00	0.08	0.06	0.05	0.10	0.03	0.21	0.39	1.61	8.69	58.33	7.74	5.18	5.46	12.04
	(0.00)	(0.00)	(0.16)	(0.07)	(0.00)	(0.43)	(0.88)	(0.12)	(0.66)	(0.16)	(0.74)	(1.05)	(2.08)	(4.39)	(9.34)	(3.74)	(4.69)	(4.67)	(4.68)
B-	0.00	0.00	0.00	0.00	0.03	0.06	0.00	0.13	0.06	0.16	0.16	0.19	0.61	2.89	10.86	51.85	10.70	8.64	13.65
	(0.00)	(0.00)	(0.00)	(0.00)	(0.85)	(0.75)	(0.00)	(0.67)	(0.20)	(0.90)	(0.99)	(2.25)	(1.63)	(3.17)	(5.90)	(11.93)	(6.35)	(7.89)	(7.31)
CCC/C	0.00	0.00	0.00	0.00	0.04	0.00	0.13	0.09	0.09	0.09	0.04	0.22	0.52	1.39	2.87	9.40	43.93	26.82	14.37
	(0.00)	(0.00)	(0.00)	(0.00)	(0.31)	(0.00)	(0.66)	(0.66)	(0.42)	(0.73)	(0.33)	(0.66)	(1.12)	(2.26)	(5.79)	(5.87)	(12.79)	(12.68)	(7.32)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Over each time span, lower ratings correspond to higher default rates (see table 24 and chart 25). This also holds true in every region worldwide (see table 25).

Chart 25



Data are identical to that found in chart 4, converted to logarithmic scale. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 24

Global Corporate Average Cumulative Default Rates (1981-2011)

	--Time horizon (years)--														
(%)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
AAA	0.00	0.03	0.14	0.25	0.37	0.49	0.55	0.64	0.71	0.78	0.81	0.85	0.89	0.97	1.06
	(0.00)	(0.01)	(0.07)	(0.13)	(0.19)	(0.26)	(0.28)	(0.28)	(0.24)	(0.21)	(0.20)	(0.19)	(0.18)	(0.19)	(0.20)
AA	0.02	0.07	0.14	0.26	0.37	0.49	0.60	0.69	0.77	0.86	0.94	1.01	1.09	1.17	1.23
	(0.01)	(0.03)	(0.04)	(0.09)	(0.15)	(0.22)	(0.29)	(0.37)	(0.38)	(0.41)	(0.43)	(0.47)	(0.44)	(0.42)	(0.41)
A	0.08	0.18	0.32	0.48	0.66	0.86	1.10	1.31	1.53	1.77	1.97	2.14	2.30	2.45	2.66
	(0.02)	(0.04)	(0.05)	(0.08)	(0.09)	(0.10)	(0.13)	(0.16)	(0.24)	(0.36)	(0.49)	(0.53)	(0.55)	(0.53)	(0.53)
BBB	0.24	0.67	1.13	1.71	2.30	2.88	3.38	3.88	4.38	4.88	5.41	5.85	6.30	6.76	7.22
	(0.06)	(0.14)	(0.17)	(0.24)	(0.31)	(0.41)	(0.50)	(0.59)	(0.73)	(0.84)	(0.93)	(0.82)	(0.67)	(0.53)	(0.43)
BB	0.90	2.70	4.80	6.80	8.61	10.34	11.85	13.21	14.49	15.59	16.49	17.29	17.97	18.55	19.24
	(0.31)	(0.56)	(0.83)	(1.20)	(1.69)	(2.30)	(2.29)	(2.43)	(2.78)	(3.04)	(3.51)	(3.55)	(3.56)	(3.36)	(3.23)
B	4.48	9.95	14.57	18.15	20.83	23.00	24.76	26.19	27.46	28.70	29.77	30.65	31.47	32.22	33.01
	(0.94)	(1.98)	(2.21)	(2.44)	(2.91)	(2.87)	(3.01)	(3.19)	(3.13)	(2.78)	(2.21)	(2.13)	(2.00)	(2.15)	(2.34)
CCC/C	26.82	35.84	41.14	44.27	46.72	47.82	48.79	49.66	50.77	51.65	52.42	53.28	54.24	55.13	55.13
	(6.99)	(7.19)	(8.32)	(9.21)	(9.33)	(7.91)	(8.14)	(8.15)	(7.82)	(6.46)	(6.62)	(6.73)	(6.54)	(5.22)	(5.22)
Investment grade	0.12	0.33	0.57	0.86	1.17	1.47	1.76	2.03	2.30	2.57	2.82	3.04	3.25	3.46	3.69
	(0.03)	(0.06)	(0.10)	(0.13)	(0.16)	(0.16)	(0.18)	(0.22)	(0.29)	(0.40)	(0.49)	(0.49)	(0.45)	(0.39)	(0.34)
Speculative grade	4.21	8.23	11.74	14.56	16.82	18.72	20.31	21.68	22.93	24.08	25.06	25.89	26.65	27.33	28.03
	(0.98)	(1.41)	(1.73)	(1.85)	(1.86)	(1.61)	(1.68)	(1.68)	(1.53)	(1.37)	(1.30)	(1.28)	(1.28)	(1.23)	(1.20)
All rated	1.57	3.10	4.47	5.62	6.58	7.41	8.12	8.73	9.30	9.83	10.29	10.68	11.05	11.38	11.74
	(0.38)	(0.60)	(0.82)	(0.94)	(0.99)	(0.93)	(0.95)	(0.88)	(0.78)	(0.61)	(0.47)	(0.47)	(0.49)	(0.55)	(0.61)

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Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

The only exceptions occur when the number of defaults is very small--such as among the higher rating categories--at the rating modifier level (see table 26). Investment-grade-rated issuers seldom default, so the number of defaults among these rating categories is very low. This small sample size can result in historical default rates that are counterintuitive. This does not imply, for example, that 'AAA' rated companies are more risky than 'AA+' rated companies but rather that both are very unlikely to default.

Table 25

Average Cumulative Default Rates For Corporates By Region (1981-2011)

	--Time horizon (years)--														
(%)	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
U.S.															
AAA	0.00	0.04	0.17	0.30	0.43	0.56	0.61	0.70	0.80	0.90	0.96	1.01	1.07	1.19	1.32
	(0.00)	(0.01)	(0.07)	(0.14)	(0.20)	(0.26)	(0.26)	(0.24)	(0.21)	(0.20)	(0.19)	(0.18)	(0.17)	(0.17)	(0.19)
AA	0.04	0.09	0.19	0.34	0.48	0.64	0.78	0.90	0.99	1.10	1.20	1.29	1.38	1.45	1.54
	(0.01)	(0.03)	(0.05)	(0.11)	(0.16)	(0.23)	(0.28)	(0.36)	(0.37)	(0.40)	(0.42)	(0.45)	(0.42)	(0.39)	(0.37)
A	0.08	0.23	0.41	0.62	0.84	1.08	1.36	1.62	1.90	2.19	2.44	2.64	2.84	3.02	3.25
	(0.03)	(0.04)	(0.07)	(0.11)	(0.12)	(0.11)	(0.14)	(0.16)	(0.20)	(0.28)	(0.39)	(0.42)	(0.43)	(0.41)	(0.39)
BBB	0.27	0.71	1.18	1.81	2.48	3.16	3.76	4.38	4.99	5.58	6.16	6.63	7.09	7.58	8.07
	(0.06)	(0.13)	(0.12)	(0.18)	(0.24)	(0.35)	(0.45)	(0.51)	(0.63)	(0.72)	(0.80)	(0.69)	(0.53)	(0.36)	(0.23)
BB	0.96	2.93	5.31	7.53	9.50	11.46	13.13	14.65	16.03	17.23	18.21	19.08	19.82	20.43	21.14
	(0.31)	(0.53)	(0.73)	(1.07)	(1.58)	(2.18)	(2.15)	(2.27)	(2.61)	(2.87)	(3.33)	(3.35)	(3.33)	(3.12)	(2.98)
B	4.59	10.29	15.22	19.06	22.02	24.41	26.37	27.94	29.31	30.61	31.75	32.67	33.51	34.28	35.06
	(0.90)	(1.90)	(2.13)	(2.35)	(2.87)	(2.87)	(3.05)	(3.26)	(3.21)	(2.85)	(2.27)	(2.21)	(2.09)	(2.26)	(2.46)
CCC/C	27.58	38.13	44.28	48.19	51.09	52.43	53.59	54.47	55.66	56.51	57.34	58.23	59.18	60.00	60.00
	(6.97)	(7.58)	(8.83)	(9.85)	(9.95)	(8.62)	(8.87)	(8.89)	(8.51)	(7.16)	(7.33)	(7.42)	(7.22)	(5.90)	(5.90)
Investment grade	0.14	0.37	0.64	0.98	1.34	1.71	2.06	2.41	2.74	3.08	3.39	3.64	3.89	4.13	4.39
	(0.03)	(0.06)	(0.10)	(0.14)	(0.17)	(0.18)	(0.20)	(0.20)	(0.27)	(0.34)	(0.42)	(0.41)	(0.37)	(0.31)	(0.25)
Speculative grade	4.49	8.91	12.81	15.95	18.47	20.60	22.37	23.88	25.23	26.46	27.50	28.39	29.19	29.88	30.58
	(0.95)	(1.37)	(1.68)	(1.77)	(1.75)	(1.43)	(1.53)	(1.54)	(1.32)	(1.05)	(0.83)	(0.79)	(0.76)	(0.74)	(0.75)
All rated	1.83	3.66	5.30	6.69	7.83	8.84	9.68	10.42	11.10	11.73	12.27	12.73	13.15	13.52	13.92
	(0.42)	(0.70)	(0.97)	(1.14)	(1.23)	(1.20)	(1.25)	(1.22)	(1.15)	(1.00)	(0.88)	(0.91)	(0.95)	(1.03)	(1.11)
Europe															
AAA	0.00	0.00	0.00	0.00	0.00	0.00	0.00								
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)								
AA	0.00	0.04	0.08	0.18	0.28	0.39	0.46								
	(0.00)	(0.03)	(0.06)	(0.11)	(0.17)	(0.23)	(0.23)								
A	0.05	0.11	0.18	0.28	0.41	0.54	0.71								
	(0.03)	(0.05)	(0.09)	(0.13)	(0.20)	(0.26)	(0.30)								
BBB	0.12	0.35	0.60	0.76	0.90	1.05	1.24								
	(0.11)	(0.28)	(0.51)	(0.57)	(0.60)	(0.61)	(0.56)								
BB	0.64	2.04	3.19	3.83	4.55	5.36	6.14								
	(0.54)	(1.37)	(2.20)	(2.55)	(3.06)	(2.99)	(2.47)								
B	3.70	9.00	12.57	14.81	16.55	17.68	18.15								
	(2.42)	(5.47)	(7.72)	(8.34)	(8.50)	(7.90)	(5.21)								
CCC/C	34.69	39.62	43.40	43.40	43.40	43.40	43.40								
	(20.31)	(21.10)	(21.95)	(21.95)	(21.95)	(21.95)	(21.95)								
Investment grade	0.06	0.16	0.27	0.38	0.50	0.62	0.76								
	(0.03)	(0.09)	(0.16)	(0.20)	(0.25)	(0.27)	(0.23)								
Speculative grade	3.36	6.51	8.74	10.03	11.15	12.06	12.69								
	(1.95)	(3.57)	(4.94)	(5.35)	(5.64)	(5.05)	(3.31)								
All rated	0.60	1.19	1.63	1.93	2.21	2.45	2.66								
	(0.30)	(0.57)	(0.78)	(0.88)	(0.95)	(0.93)	(0.74)								
Emerging markets															
AAA	0.00	0.00	0.00	0.00	0.00										
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)										
AA	0.00	0.00	0.00	0.00	0.00										
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)										
A	0.08	0.08	0.08	0.08	0.08										
	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)										
BBB	0.21	1.02	1.94	3.01	4.02										
	(0.44)	(0.91)	(1.54)	(2.54)	(3.65)										

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BB	0.97	2.64	4.24	5.82	6.98
	(0.75)	(2.37)	(3.72)	(4.75)	(6.35)
B	3.41	6.84	9.41	11.41	12.41
	(3.66)	(5.99)	(8.31)	(9.61)	(9.84)
CCC/C	18.77	21.54	23.39	24.37	25.42
	(10.37)	(11.75)	(13.10)	(28.78)	(6.48)
Investment grade	0.16	0.69	1.29	2.00	2.68
	(0.27)	(0.61)	(1.09)	(1.83)	(2.57)
Speculative grade	3.10	5.54	7.54	9.24	10.34
	(2.17)	(3.62)	(4.97)	(5.69)	(6.94)
All rated	1.87	3.51	4.94	6.24	7.17
	(1.26)	(2.30)	(3.11)	(3.85)	(4.78)

Note: Numbers in parentheses are standard deviations. Default rates for Europe and the emerging markets are calculated for the period 1996-2010 because of sample size considerations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 26

Global Corporate Average Cumulative Default Rates By Rating Modifier (1981-2011)

(%)	--Time horizon (years)--														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
AAA	0.00	0.03	0.14	0.25	0.37	0.49	0.55	0.64	0.71	0.78	0.81	0.85	0.89	0.97	1.06
	(0.00)	(0.01)	(0.07)	(0.13)	(0.19)	(0.26)	(0.28)	(0.28)	(0.24)	(0.21)	(0.20)	(0.19)	(0.18)	(0.19)	(0.20)
AA+	0.00	0.06	0.06	0.12	0.19	0.25	0.32	0.39	0.46	0.53	0.61	0.70	0.79	0.89	1.00
	(0.00)	(0.06)	(0.06)	(0.22)	(0.48)	(0.86)	(1.64)	(1.63)	(1.61)	(1.60)	(1.58)	(1.56)	(1.54)	(1.52)	(1.49)
AA	0.02	0.04	0.09	0.25	0.39	0.51	0.64	0.75	0.84	0.94	1.01	1.07	1.18	1.24	1.31
	(0.01)	(0.01)	(0.03)	(0.07)	(0.10)	(0.13)	(0.17)	(0.18)	(0.18)	(0.25)	(0.28)	(0.27)	(0.22)	(0.21)	(0.19)
AA-	0.03	0.11	0.22	0.32	0.42	0.55	0.64	0.72	0.79	0.87	0.96	1.06	1.09	1.17	1.22
	(0.02)	(0.05)	(0.12)	(0.25)	(0.39)	(0.58)	(0.67)	(0.82)	(0.87)	(0.84)	(0.81)	(1.14)	(1.14)	(1.16)	(1.17)
A+	0.06	0.12	0.26	0.44	0.58	0.71	0.86	1.03	1.22	1.43	1.64	1.83	2.07	2.37	2.63
	(0.03)	(0.21)	(0.19)	(0.15)	(0.14)	(0.15)	(0.17)	(0.19)	(0.12)	(0.22)	(0.38)	(0.43)	(0.47)	(0.59)	(0.63)
A	0.08	0.20	0.32	0.47	0.63	0.85	1.07	1.28	1.53	1.82	2.05	2.20	2.32	2.40	2.65
	(0.03)	(0.05)	(0.09)	(0.13)	(0.16)	(0.13)	(0.18)	(0.17)	(0.20)	(0.28)	(0.41)	(0.48)	(0.52)	(0.49)	(0.44)
A-	0.08	0.22	0.37	0.53	0.76	1.01	1.37	1.63	1.84	2.01	2.16	2.33	2.48	2.58	2.65
	(0.04)	(0.10)	(0.15)	(0.24)	(0.45)	(0.69)	(0.98)	(1.07)	(1.25)	(1.34)	(1.28)	(1.22)	(1.17)	(1.13)	(1.14)
BBB+	0.15	0.42	0.74	1.06	1.43	1.84	2.15	2.47	2.84	3.19	3.51	3.73	4.04	4.52	5.06
	(0.09)	(0.21)	(0.36)	(0.48)	(0.53)	(0.62)	(0.70)	(0.77)	(0.77)	(0.82)	(0.58)	(0.57)	(0.61)	(0.72)	(0.88)
BBB	0.21	0.55	0.86	1.33	1.82	2.29	2.73	3.19	3.70	4.20	4.76	5.25	5.67	5.83	6.12
	(0.09)	(0.32)	(0.31)	(0.35)	(0.43)	(0.48)	(0.60)	(0.80)	(0.95)	(1.15)	(1.25)	(1.09)	(0.95)	(0.90)	(0.81)
BBB-	0.37	1.11	1.98	3.02	4.03	4.94	5.75	6.53	7.15	7.85	8.56	9.22	9.85	10.76	11.37
	(0.12)	(0.35)	(0.60)	(0.76)	(1.09)	(1.42)	(1.60)	(1.33)	(1.40)	(1.22)	(1.28)	(1.23)	(1.10)	(0.90)	(0.86)
BB+	0.51	1.41	2.64	3.87	5.01	6.19	7.23	7.95	8.93	9.87	10.52	11.20	11.75	12.22	13.11
	(0.28)	(0.72)	(1.90)	(2.61)	(3.06)	(3.27)	(3.65)	(4.01)	(4.70)	(5.09)	(4.93)	(4.72)	(4.50)	(4.42)	(4.29)
BB	0.76	2.32	4.48	6.43	8.32	9.99	11.43	12.68	13.76	14.72	15.63	16.45	16.92	17.20	17.59
	(0.27)	(0.35)	(0.76)	(0.92)	(1.26)	(1.28)	(1.46)	(1.66)	(1.44)	(1.51)	(1.07)	(1.32)	(1.47)	(1.55)	(1.65)
BB-	1.23	3.74	6.31	8.81	10.96	13.08	14.91	16.74	18.33	19.64	20.70	21.55	22.47	23.33	24.16
	(0.41)	(0.76)	(0.93)	(1.27)	(1.80)	(2.79)	(2.91)	(3.11)	(3.46)	(3.81)	(4.50)	(4.76)	(4.82)	(4.51)	(4.35)
B+	2.50	6.75	10.88	14.44	17.14	19.25	21.19	22.93	24.49	26.06	27.32	28.30	29.27	30.15	30.96
	(0.63)	(1.92)	(2.69)	(3.25)	(3.77)	(4.18)	(4.54)	(4.82)	(4.95)	(2.48)	(2.65)	(2.77)	(2.87)	(2.98)	(3.10)
B	5.46	11.87	16.84	20.29	22.87	25.38	26.81	27.85	28.73	29.57	30.46	31.28	32.02	32.71	33.54
	(1.66)	(2.72)	(2.99)	(3.34)	(4.03)	(3.67)	(3.58)	(3.75)	(3.70)	(3.37)	(2.65)	(2.48)	(2.22)	(2.36)	(2.52)
B-	8.64	16.22	21.89	25.86	28.76	30.56	32.29	33.29	34.00	34.52	35.10	35.63	35.92	36.25	36.79
	(2.99)	(5.28)	(6.01)	(6.53)	(6.82)	(7.10)	(7.54)	(7.74)	(7.90)	(7.95)	(7.36)	(7.52)	(7.62)	(7.72)	(7.88)
CCC/C	26.82	35.84	41.14	44.27	46.72	47.82	48.79	49.66	50.77	51.65	52.42	53.28	54.24	55.13	55.13
	(6.99)	(7.19)	(8.32)	(9.21)	(9.33)	(7.91)	(8.14)	(8.15)	(7.82)	(6.46)	(6.62)	(6.73)	(6.54)	(5.22)	(5.22)
Investment grade	0.12	0.33	0.57	0.86	1.17	1.47	1.76	2.03	2.30	2.57	2.82	3.04	3.25	3.46	3.69
	(0.03)	(0.06)	(0.10)	(0.13)	(0.16)	(0.16)	(0.18)	(0.22)	(0.29)	(0.40)	(0.49)	(0.49)	(0.45)	(0.39)	(0.34)
Speculative grade	4.21	8.23	11.74	14.56	16.82	18.72	20.31	21.68	22.93	24.08	25.06	25.89	26.65	27.33	28.03
	(0.98)	(1.41)	(1.73)	(1.85)	(1.86)	(1.61)	(1.68)	(1.68)	(1.53)	(1.37)	(1.30)	(1.28)	(1.28)	(1.23)	(1.20)
All rated	1.57	3.10	4.47	5.62	6.58	7.41	8.12	8.73	9.30	9.83	10.29	10.68	11.05	11.38	11.74
	(0.38)	(0.60)	(0.82)	(0.94)	(0.99)	(0.93)	(0.95)	(0.88)	(0.78)	(0.61)	(0.47)	(0.47)	(0.49)	(0.55)	(0.61)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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Gini Ratios And Lorenz Curves

A quantitative analysis of the performance of Standard & Poor's ratings shows that corporate ratings continue to correlate with the level of default risk across several time horizons. To measure ratings performance, the cumulative share of defaulters is plotted against the

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cumulative share of issuers by rating in a Lorenz curve to visually render the accuracy of its rank ordering (for definition and methodology, refer to Appendix III). Over the long term, the global average one-year transition to default has a one-year Gini coefficient of 82.1%; three-year, 75.5%; five-year, 71.6%; and seven-year, 69.8% (see charts 26-29).

Table 27 displays the variation in Gini coefficients by region, and table 28 shows them by broad sector. As expected, the Gini coefficients decline over time because longer time horizons allow greater opportunity for credit degradation among higher-rated entities. In the one-year global Lorenz curve, for example, 95% of defaults occurred in the speculative-grade category ('BB+' or lower), while ratings of 'BB+' or lower constituted only 35.3% of all corporate ratings (see chart 26). Looking at the seven-year Lorenz curve, speculative-grade issuers constituted 85.2% of defaulters and only 32.6% of the entire sample (see chart 29). If the rank ordering of ratings had little predictive value, the cumulative share of defaulting corporate entities and the cumulative share of all entities at each rating would be nearly the same, producing a Gini ratio of zero.

Table 27

Corporate Gini Coefficients By Region (1981-2011)

	--Time horizon (years)--			
Region	**1**	**3**	**5**	**7**
Global				
Weighted average	82.05	75.47	71.58	69.81
Average	84.17	77.35	73.13	70.26
Standard deviation	(5.59)	(5.04)	(5.24)	(5.03)
U.S.				
Weighted average	80.50	73.82	70.14	68.45
Average	82.79	75.35	71.11	68.47
Standard deviation	(6.98)	(6.86)	(6.79)	(5.96)
Europe				
Weighted average	90.76	85.52	80.34	76.17
Average	92.37	87.35	79.12	69.89
Standard deviation	(5.64)	(6.33)	(7.12)	(11.35)

Note: Numbers in parentheses are standard deviations. Averages and standard deviations for Europe calculated for the period 1996-2010 because of sample size considerations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 28

Gini Coefficients For Global Corporates By Broad Sector (1981-2011)

	--Time horizon (years)--			
Sector	**1**	**3**	**5**	**7**
Financial				
Weighted average	77.75	66.48	59.75	57.69
Average	82.79	71.06	63.50	59.38
Standard deviation	(16.90)	(14.51)	(15.64)	(13.66)
Nonfinancial				
Weighted average	80.97	74.19	70.17	68.28
Average	83.56	76.53	72.38	69.45
Standard deviation	(6.49)	(5.53)	(5.50)	(5.20)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 26

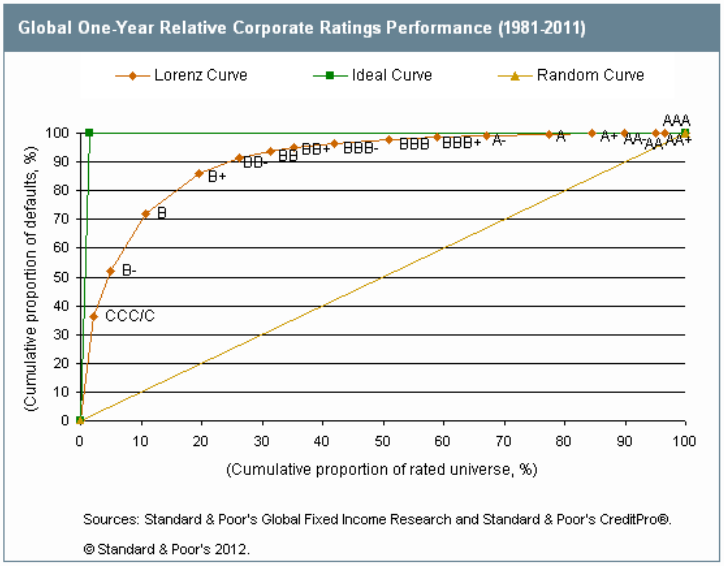

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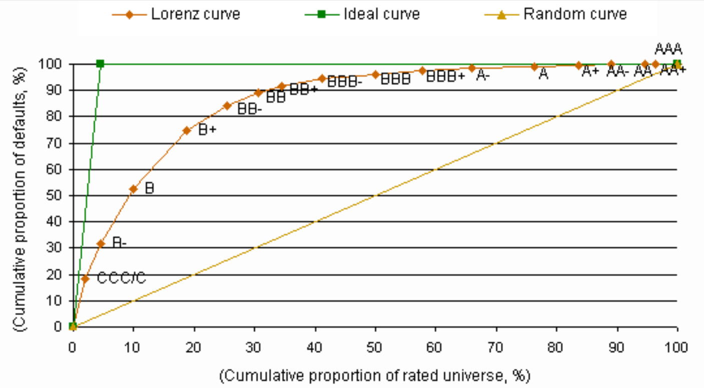
Chart 27

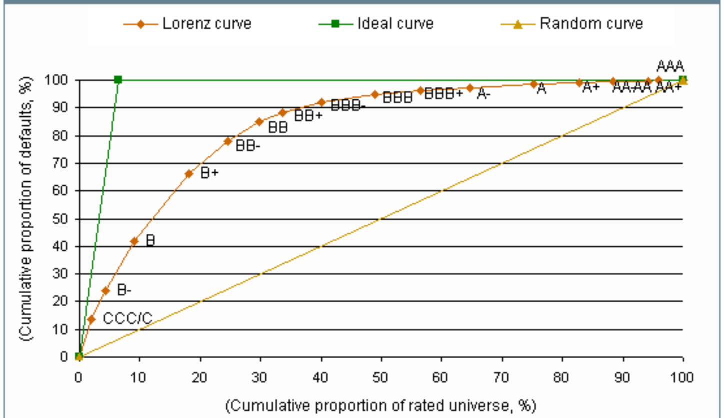
Global Three-Year Relative Corporate Ratings Performance (1981-2011)



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 28

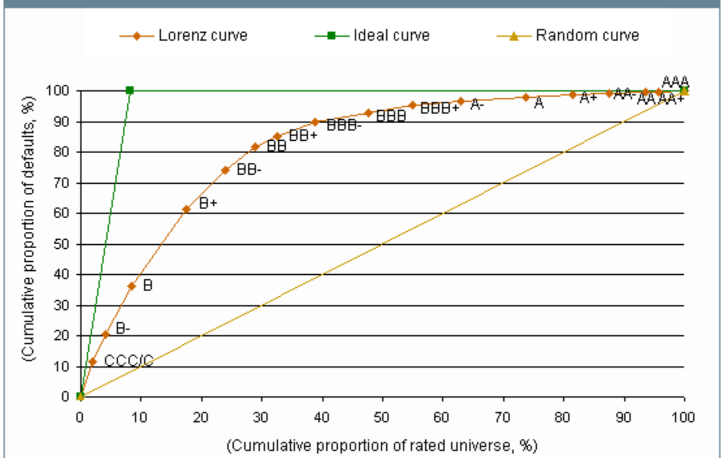
Global Five-Year Relative Corporate Ratings Performance (1981-2011)



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Chart 29

Global Seven-Year Relative Corporate Ratings Performance (1981-2011)



Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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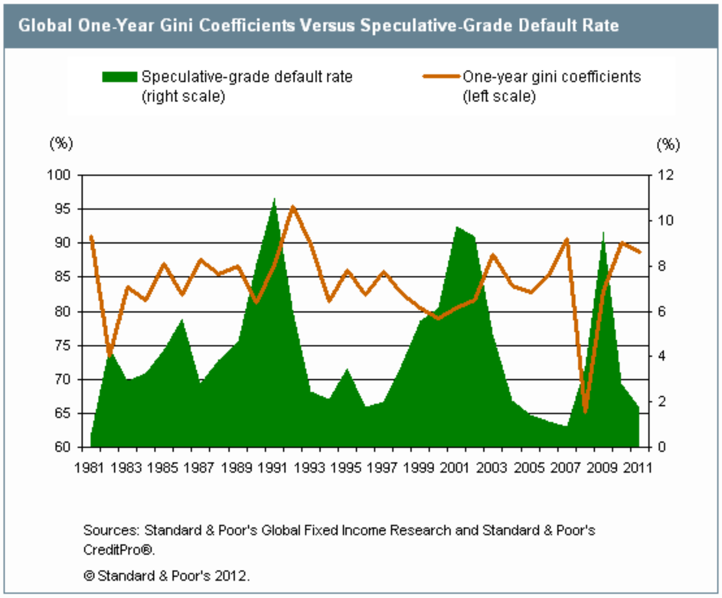
Chart 30



Global One-Year Gini Coefficients Versus Speculative-Grade Default Rate

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

The pattern of one-year Gini coefficients appears to be broadly cyclical (see chart 30). Trends in the one-year Gini ratio emerge during periods of both extremes in the default cycle, which is a reflection of the natural relationship between the two. In periods of high defaults, there tends to be greater variation with respect to how the defaults are distributed across the ratings spectrum, which reduces the Gini. That is, when default pressure is high, the economic conditions are such that there is an increased likelihood of companies from across the rating spectrum suffering a more rapid deterioration of credit quality. The one-year Gini was 88.7% in 2011--the sixth highest on record. This is marginally lower than the prior year's as a result of the default of MF Global, which began the year rated investment grade. Conversely, in 2010, all of the defaulters began the year rated speculative grade.

Appendix I: Default Methodology And Definitions

This long-term corporate default and rating transition study uses the CreditPro® database of long-term local currency issuer credit ratings. Most exhibits in this study are the direct output of the CreditPro interface, while others are based off of manual manipulation of the underlying database. Those that we created through manual manipulation were charts 3, 7-13, 17, and 25-30, as well as tables 2, 10-13, 17, 18, 27, 28, and the first column of table 1. The portions of the tables that present summary descriptive statistics, including the standard deviations in the various transition and cumulative default rate tables, were also the result of end-user calculations.

An issuer credit rating reflects Standard & Poor's forward-looking opinion of a company's overall capacity to pay its obligations (that is, its fundamental creditworthiness). This opinion focuses on the obligor's ability and willingness to meet its financial commitments on a timely basis, and it generally indicates the likelihood of default regarding all financial obligations of the firm. It is not necessary for a company to have rated debt to be assigned an issuer credit rating.

Although the rating on a company's very senior forms of secured debt, particularly ones with strong covenants, could occasionally be higher than the issuer credit rating on the company, specific issues are typically rated as high as or lower than these ratings, depending on their relative priority within the company's debt structure. If they are speculative grade, issuer credit ratings are generally two notches higher than subordinated debt ratings. Otherwise, they are generally one notch higher. Therefore, although a 'BB+' issuer credit rating is generally paired with a 'BB-' subordinated debt rating, a 'AA' issuer credit rating usually corresponds to a 'AA-' subordinated rating.

Standard & Poor's ongoing enhancement of the CreditPro® database used to generate this study could lead to outcomes that differ to some degree from those reported in previous studies. However, this poses no continuity problem because each study reports statistics back to Dec. 31, 1980. Therefore, each annual default study is self-contained and effectively supersedes all previous versions.

Issuers included in this study

The study analyzes the rating histories of 15,299 companies that Standard & Poor's rated as of Dec. 31, 1980, or that were first rated between that date and Dec. 31, 2011. These include industrials, utilities, financial institutions, and insurance companies around the world with long-term local currency ratings. The analysis excludes public information ("pi") ratings and ratings based on the guarantee of another company. Structured finance vehicles, public-sector issuers, and sovereign issuers are the subject of separate default and transition studies, and we exclude them from this study.

We excluded subsidiaries with debt that is fully guaranteed by a parent or with default risk that is considered identical to that of their parents. The latter are companies with obligations that are not legally guaranteed by a parent but that have operating or financing activities that are so inextricably entwined with those of the parent that it would be impossible to imagine the default of one and not the other. At times, however, some of these subsidiaries might not yet have been covered by a parent's guarantee, or the relationship that combines the default risk of parent and subsidiary might have come to an end or might not have begun. We included such subsidiaries for the period during which they had a distinct and separate risk of default.

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Definition of default

A default is recorded on the first occurrence of a payment default on any financial obligation, rated or unrated, other than a financial obligation subject to a bona fide commercial dispute. An exception is an interest payment that is missed on the due date but is made within the grace period. Preferred stock is not considered a financial obligation; thus, a missed preferred stock dividend is not normally equated with default. We do consider distressed exchanges defaults when the debtholders are coerced into accepting substitute instruments with lower coupons, longer maturities, or any other diminished financial terms.

Issue ratings are usually revised to 'D' following a company's default on the corresponding obligation. In addition, Standard & Poor's uses 'SD' when it believes that an obligor that has selectively defaulted on a specific issue or class of obligations will continue to meet its payment obligations on other issues or classes of obligations in a timely matter. 'R' indicates that an obligor is under regulatory supervision owing to its financial condition. This does not necessarily indicate a default event, but the regulator might have the power to favor one class of obligations over others or pay some obligations and not others. We deem 'D', 'SD', and 'R' issuer ratings as defaults for the purposes of this study. A default is assumed to take place on the earliest of: the date Standard & Poor's revised the ratings to 'D', 'SD', or 'R'; the date a debt payment was missed; the date a distressed exchange offer was announced; or the date the debtor filed or was forced into bankruptcy.

Calculations

Static pool methodology. Standard & Poor's conducts its default studies on the basis of groupings called static pools. We form static pools by grouping issuers by rating category at the beginning of each year covered by the study. Each static pool is followed from that point forward. All companies included in the study are assigned to one or more static pools. When an issuer defaults, we assign that default back to all of the static pools to which the issuer belonged.

Standard & Poor's uses the static pool methodology to avoid certain pitfalls in estimating default rates. This is to ensure that default rates account for rating migration and to allow for default rates to be calculated across multiperiod time horizons. Some methods for calculating default and rating transition rates might charge defaults against only the initial rating on the issuer, ignoring more recent rating changes that supply more current information. Other methods may calculate default rates using only the most recent year's default and rating data, which may yield comparatively low default rates during periods of high rating activity because they ignore prior years' default activity.

The pools are static in the sense that their membership remains constant over time. Each static pool can be interpreted as a buy-and-hold portfolio. Because errors, if any, are corrected by every new update and because the criteria for inclusion or exclusion of companies in the default study are subject to minor revisions as time goes by, it is not possible to compare static pools across different studies. Therefore, every new update revises results back to the same starting date of Dec. 31, 1980, so as to avoid continuity problems.

Entities that have had ratings withdrawn--that is, revised to 'NR'--are surveilled with the aim of capturing a potential default. We exclude these companies, as well as those that have defaulted, from subsequent static pools.

For instance, the 1981 static pool consists of all companies rated as of 12:01 a.m. Jan. 1, 1981. Adding those companies first rated in 1981 to the surviving members of the 1981 static pool forms the 1982 static pool. All rating changes that took place are reflected in the newly formed 1982 static pool. We used the same method to form static pools for 1983 through 2011. From Jan. 1, 1981, to Dec. 31, 2011, a total of 13,914 first-time rated organizations were added to form new static pools, while we excluded 2,068 defaulting companies and 7,137 companies with a last rating that was classified as 'NR'.

Consider the following example: An issuer is originally rated 'BB' in mid-1986 and is downgraded to 'B' in 1988. This is followed by a rating withdrawal in 1990 and a default in 1993. This hypothetical company would be included in the 1987 and 1988 pools with the 'BB' rating, which it was rated at the beginning of those years; likewise, it would be included in the 1989 and 1990 pools with the 'B' rating. It would not be part of the 1986 pool because it was not rated as of the first day of that year, and it would not be included in any pool after the last day of 1990 because the rating had been withdrawn by then. Yet each of the four pools in which this company was included (1987-1990) would record its 1993 default at the appropriate time horizon.

Ratings are withdrawn when an entity's entire debt is paid off or when the program or programs rated are terminated and the relevant debt extinguished. They may also occur as a result of mergers and acquisitions. Others are withdrawn because of a lack of cooperation, particularly when a company is experiencing financial difficulties and refuses to provide all the information needed to continue surveillance on the ratings, or at the entity's request.

Default rate calculation. Annual default rates were calculated for each static pool--first in units and later as percentages with respect to the number of issuers in each rating category. Finally, we combined these percentages to obtain cumulative default rates for the 31 years covered by the study (see tables 24-26 and 30-32).

Issuer-weighted default rates. We calculated the averages that appear in this study based on the number of issuers rather than the dollar amounts affected by defaults or rating changes. Although dollar amounts provide information about the portion of the market that is affected by defaults or rating changes, issuer-weighted averages are a more useful measure of the performance of ratings.

Many practitioners utilize statistics from this default study and CreditPro® to estimate "probability of default" and "probability of rating transition." It is important to note that Standard & Poor's ratings do not imply a specific probability of default.

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Average cumulative default rate calculation. We derived cumulative default rates that average the experience of all static pools by calculating marginal default rates, conditional on survival (survivors being nondefaulters) for each possible time horizon and for each static pool, weight averaging the conditional marginal default rates, and accumulating the average conditional marginal default rates (see

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tables 24-26 and 31-33). We calculated conditional default rates by dividing the number of issuers in a static pool that default at a specific time horizon by the number of issuers that survived (did not default) to that point in time. Weights are based on the number of issuers in each static pool. Cumulative default rates are one minus the product of the proportion of survivors (nondefaulters).

For instance, the weighted-average first-year default rate for all speculative-grade-rated companies for all 31 pools was 4.21%, meaning that an average of 95.79% survived one year. Similarly, the second- and third-year conditional marginal averages were 4.20% for the first 30 pools (95.80% of those companies that did not default in the first year survived the second year) and 3.82% for the first 29 pools (96.18% of those companies that did not default by the second year survived the third year), respectively. Multiplying 95.79% by 95.80% results in a 91.77% survival rate to the end of the second year, which is a two-year average cumulative default rate of 8.23%. Multiplying 91.77% by 96.18% results in an 88.27% survival rate to the end of the third year, which is a three-year average cumulative default rate of 11.74%.

Time sample

This update limits the reporting of default rates to the 15-year time horizon. However, the data was gathered for 31 years, and all calculations are based on the rating experience of that period. The maturities of most obligations are much shorter than 15 years. In addition, average default statistics become less reliable at longer time horizons as the sample size becomes smaller and the cyclical nature of default rates increases its effect on averages.

Default patterns share broad similarities across all static pools, suggesting that Standard & Poor's rating standards have been consistent over time. Adverse business conditions tend to coincide with default upswings for all pools. These upswings have hit speculative-grade issuers the hardest, but investment-grade default rates also increase in stressful periods.

Transition analysis

Transition rates compare issuer ratings at the beginning of a time period with ratings at the end of the period. To compute one-year rating transition rates by rating category, we compared the rating on each entity at the end of a particular year with the rating at the beginning of the same year. An issuer that remained rated for more than one year was counted as many times as the number of years it was rated. For instance, an issuer continually rated from the middle of 1984 to the middle of 1991 would appear in the six consecutive one-year transition matrices from 1985 to 1990. All 1981 static pool members still rated on Dec. 31, 2011, had 31 one-year transitions, while companies first rated between Jan. 1, 2011, and Dec. 31, 2011, had only one. Table 29 displays the summary of one-year transitions within the investment-grade and speculative-grade rating categories.

Each one-year transition matrix displays all rating movements between letter categories from the beginning of the year through year-end. For each rating listed in the matrix's left-most column, there are nine ratios listed in the rows, corresponding to the ratings from 'AAA' to 'D', plus an entry for NR (see table 22).

Table 29

Summary Of One-Year Global Corporate Rating Transitions

		--Investment-grade rating distribution at year-end--			
Year	Number of investment-grade issuers on Jan. 1	Investment grade (%)	Speculative grade* (%)	Defaulted§ (%)	Rating withdrawn (%)
1981	1,064	97.37	1.41	0.00	1.22
1982	1,093	93.60	3.02	0.18	3.20
1983	1,114	94.16	2.07	0.09	3.68
1984	1,174	95.32	2.30	0.17	2.21
1985	1,210	93.06	3.55	0.00	3.39
1986	1,327	89.98	3.84	0.15	6.03
1987	1,324	90.18	3.02	0.00	6.80
1988	1,337	91.77	2.77	0.00	5.46
1989	1,381	93.12	2.68	0.14	4.06
1990	1,425	94.60	2.10	0.14	3.16
1991	1,462	96.24	1.85	0.14	1.78
1992	1,614	96.41	1.18	0.00	2.42
1993	1,766	92.47	1.53	0.00	6.00
1994	1,849	95.83	0.76	0.05	3.35
1995	2,057	95.58	1.12	0.05	3.26
1996	2,256	94.51	0.62	0.00	4.88
1997	2,507	93.58	1.15	0.08	5.19
1998	2,789	90.39	2.19	0.14	7.28
1999	2,892	90.87	1.59	0.17	7.37
2000	2,953	91.70	1.73	0.24	6.33
2001	3,030	90.69	2.61	0.26	6.44
2002	3,137	89.55	4.02	0.41	6.02
2003	3,054	92.50	2.49	0.10	4.91
2004	3,171	94.10	1.01	0.03	4.86
2005	3,282	92.84	1.62	0.03	5.51
2006	3,304	93.86	1.45	0.00	4.69
2007	3,381	90.42	1.71	0.00	7.87

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2008	3,382	92.23	1.92	0.41	5.44
2009	3,426	89.70	3.41	0.32	6.57
2010	3,263	95.01	0.95	0.00	4.05
2011	3,331	93.82	1.69	0.03	4.47
Weighted average	70,355	92.76	1.97	0.12	5.15
Median		93.12	1.85	0.08	4.88
Standard deviation		2.18	0.91	0.12	1.72
Minimum		89.55	0.62	0.00	1.22
Maximum		97.37	4.02	0.41	7.87

		--Speculative-grade rating distribution at year-end--			
	Number of speculative-grade issuers on Jan. 1	**Investment grade† (%)**	**Speculative grade (%)**	**Defaulted (%)**	**Rating withdrawn (%)**
1981	321	4.67	90.03	0.62	4.67
1982	340	2.65	80.88	4.41	12.06
1983	341	3.23	83.58	2.93	10.26
1984	368	4.89	86.95	3.26	4.89
1985	418	3.83	85.89	4.31	5.98
1986	530	3.02	82.26	5.66	9.06
1987	681	3.52	79.59	2.79	14.10
1988	756	3.57	79.50	3.84	13.10
1989	751	5.19	74.84	4.66	15.31
1990	692	3.18	75.00	8.09	13.73
1991	589	2.89	78.10	11.04	7.98
1992	526	6.28	78.71	6.08	8.94
1993	561	4.82	76.65	2.50	16.04
1994	713	4.07	85.97	2.10	7.85
1995	824	3.76	84.95	3.52	7.77
1996	887	4.73	81.06	1.80	12.40
1997	1,000	4.30	81.09	2.00	12.60
1998	1,315	2.97	83.88	3.65	9.51
1999	1,659	1.33	81.85	5.55	11.27
2000	1,774	2.14	83.48	6.14	8.23
2001	1,776	1.52	79.39	9.74	9.35
2002	1,696	1.89	79.78	9.32	9.02
2003	1,788	1.57	82.04	4.98	11.41
2004	1,905	2.15	84.56	2.05	11.23
2005	2,086	3.07	82.45	1.44	13.04
2006	2,222	2.12	82.49	1.13	14.27
2007	2,348	3.02	82.24	0.89	13.84
2008	2,469	2.19	83.92	3.56	10.33
2009	2,343	1.28	78.19	9.52	11.01
2010	2,234	2.37	85.41	2.82	9.40
2011	2,516	2.26	84.78	1.71	11.25
Weighted average	38,429	2.66	82.09	4.21	11.04
Median		3.02	82.24	3.56	11.01
Standard deviation		1.25	3.48	2.81	2.89
Minimum		1.28	74.84	0.62	4.67
Maximum		6.28	90.03	11.04	16.04

*Fallen angels that survived to Jan. 1 of the year after they were downgraded. §Investment-grade defaulters. †Rising stars. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Multiyear transitions. Multiyear transitions were also calculated for periods of two up to 20 years. In this case, we compared the rating at the beginning of the multiyear period with the rating at the end. For example, three-year transition matrices were the result of comparing ratings at the beginning of the years 1981-2009 with the ratings at the end of the years 1983-2011. Otherwise, the methodology was identical to that used for single-year transitions.

Average transition matrices were calculated on the basis of the multiyear matrices just described. These average matrices are a true summary, the ratios of which represent the historical incidence of the ratings listed on the first column changing to the ones listed on the top row over the course of the multiyear period (see tables 33-40).

Comparing transition rates with default rates. Rating transition rates may be compared with the marginal and cumulative default rates described in the previous section. For example, note that the one-year default rate column of table 24 is equivalent to column 'D' of the average one-year transition matrix in tables 21 and 33. However, the two-year default rate column in table 24 is not the same as column 'D' of the average two-year transition matrix in table 34. This difference results from the different static pools used to calculate

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transition to default and average cumulative default rates. Average cumulative default rates are the summary of all static pools from 1981 -2011, while the number of pools used in the average transition rate is limited by the transition's time horizon.

Initial-to-last transitions and default rates. These transition rates compare issuer ratings from the time of first rating to the last rating, regardless of the time elapsed in the interim. They provide a roadmap to all of the historically observed rating "states" inhabited by corporate ratings during their lifetimes. Tables 45-48 display the initial-to-last transitions separately for three broad sectors--nonfinancials, financial institutions, and insurance. Initial-to-last default rates are calculated based on the initial rating of each defaulter, and encompass varying time horizons. For example, in table 47, a default rate of 0.77% refers to the total share of defaulting issuers from the 130 financial institutions that received a first rating of 'AAA' in the previous 31 years.

Table 30

Static Pool Cumulative Global Corporate Default Rates Among All Ratings (1981-2011) (%)

		--Time horizon (years)--														
Year	No. issuers	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1981	1,385	0.14	1.37	2.09	2.89	3.54	4.91	5.34	6.14	6.71	7.80	9.46	9.96	10.47	10.54	10.76
1982	1,433	1.19	1.88	2.72	3.42	4.82	5.16	5.93	6.42	7.54	9.35	9.84	10.40	10.47	10.68	10.68
1983	1,455	0.76	1.58	2.41	3.99	4.40	5.43	5.91	7.01	9.00	9.55	10.10	10.17	10.38	10.38	10.45
1984	1,542	0.91	1.95	3.76	4.22	5.25	5.97	7.13	8.82	9.40	9.99	10.05	10.25	10.25	10.38	10.38
1985	1,628	1.11	3.01	3.56	4.91	5.77	7.06	8.91	9.46	9.95	10.01	10.32	10.32	10.44	10.44	10.75
1986	1,857	1.72	2.32	3.61	4.47	5.87	7.75	8.40	8.94	9.10	9.37	9.48	9.69	9.80	10.07	10.50
1987	2,005	0.95	2.39	3.84	5.69	8.23	9.33	10.07	10.32	10.67	10.82	11.02	11.12	11.42	11.92	12.97
1988	2,093	1.39	3.01	5.16	8.22	9.32	10.08	10.32	10.80	10.94	11.23	11.42	11.75	12.47	13.43	14.38
1989	2,132	1.74	4.32	7.83	9.01	9.80	10.13	10.55	10.69	10.98	11.35	11.68	12.34	13.32	14.21	14.68
1990	2,117	2.74	6.14	7.56	8.36	8.69	9.16	9.26	9.64	10.11	10.49	11.29	12.28	13.27	13.79	13.93
1991	2,051	3.27	4.78	5.31	5.66	6.19	6.29	6.63	7.07	7.46	8.14	9.17	10.24	10.73	10.92	11.07
1992	2,140	1.50	2.01	2.34	2.94	3.08	3.41	3.83	4.16	4.86	5.84	6.92	7.34	7.52	7.66	7.80
1993	2,327	0.60	1.07	1.98	2.19	2.58	3.01	3.44	4.21	5.29	6.40	6.83	7.00	7.18	7.39	7.52
1994	2,562	0.62	1.76	2.15	2.62	3.08	3.94	4.96	6.25	7.42	7.92	8.16	8.31	8.59	8.70	9.29
1995	2,881	1.04	1.53	2.01	2.57	3.54	4.55	6.35	7.71	8.30	8.54	8.75	8.99	9.09	9.61	10.48
1996	3,143	0.51	1.08	1.81	2.96	3.98	5.70	7.19	7.86	8.15	8.37	8.59	8.72	9.26	10.12	10.28
1997	3,507	0.63	1.60	2.91	4.31	6.22	7.96	8.87	9.15	9.38	9.67	9.81	10.41	11.26	11.35	11.46
1998	4,104	1.27	3.22	5.19	7.82	10.01	11.23	11.72	12.04	12.35	12.50	13.13	14.08	14.18	14.30	
1999	4,551	2.13	4.64	7.98	10.83	12.30	12.85	13.21	13.56	13.71	14.50	15.67	15.84	15.97		
2000	4,727	2.45	6.03	9.14	10.81	11.51	11.95	12.31	12.52	13.39	14.79	14.96	15.13			
2001	4,806	3.77	7.28	9.22	9.93	10.45	10.80	11.01	11.86	13.34	13.52	13.69				
2002	4,833	3.54	5.55	6.33	6.79	7.14	7.35	8.28	9.87	10.08	10.24					
2003	4,842	1.90	2.71	3.18	3.57	3.78	4.75	6.55	6.82	6.98						
2004	5,076	0.79	1.30	1.69	1.93	2.96	4.91	5.24	5.46							
2005	5,368	0.58	0.97	1.30	2.51	4.75	5.23	5.53								
2006	5,526	0.45	0.85	2.30	4.94	5.54	5.95									
2007	5,729	0.37	1.99	5.18	6.02	6.48										
2008	5,851	1.74	5.45	6.46	6.90											
2009	5,769	4.06	5.15	5.62												
2010	5,497	1.15	1.80													
2011	5,847	0.75														
Summary statistics																
Marginal average		1.57	1.56	1.41	1.21	1.02	0.89	0.76	0.67	0.62	0.59	0.52	0.44	0.41	0.38	0.40
Cumulative average		1.57	3.10	4.47	5.62	6.58	7.41	8.12	8.73	9.30	9.83	10.29	10.68	11.05	11.38	11.74
Standard deviation		1.06	1.84	2.38	2.70	2.83	2.78	2.68	2.58	2.44	2.34	2.35	2.34	2.24	2.03	2.01
Median		1.15	2.16	3.61	4.69	5.77	6.13	7.19	8.88	9.38	9.83	10.05	10.28	10.47	10.49	10.68
Minimum		0.14	0.85	1.30	1.93	2.58	3.01	3.44	4.16	4.86	5.84	6.83	7.00	7.18	7.39	7.52
Maximum		4.06	7.28	9.22	10.83	12.30	12.85	13.21	13.56	13.71	14.79	15.67	15.84	15.97	14.30	14.68

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 31

Static Pool Cumulative Global Corporate Default Rates Among All Investment-Grade Ratings (1981-2011) (%)

		--Time horizon (years)--														
Year	No. issuers	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1981	1,064	0.00	0.38	0.38	0.47	0.66	1.03	1.32	2.07	2.26	3.01	4.04	4.32	4.51	4.51	4.70
1982	1,093	0.18	0.27	0.37	0.55	1.01	1.28	2.01	2.20	3.02	4.12	4.39	4.67	4.67	4.85	4.85
1983	1,114	0.09	0.36	0.45	0.90	1.08	1.62	1.71	2.51	3.59	3.95	4.22	4.22	4.40	4.40	4.40
1984	1,174	0.17	0.26	0.60	0.77	1.19	1.36	2.04	2.98	3.32	3.58	3.58	3.75	3.75	3.83	3.83
1985	1,210	0.00	0.17	0.25	0.83	0.99	1.74	2.73	3.06	3.31	3.31	3.55	3.55	3.72	3.72	3.88
1986	1,327	0.15	0.15	0.53	0.68	1.21	2.11	2.49	2.64	2.64	2.86	2.86	3.01	3.09	3.24	3.54

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1987	1,324	0.00	0.15	0.38	0.83	1.74	2.27	2.42	2.49	2.64	2.64	2.79	2.87	3.02	3.17	4.00
1988	1,337	0.00	0.22	0.37	0.97	1.50	1.65	1.72	1.87	1.87	2.02	2.02	2.17	2.32	2.99	3.74
1989	1,381	0.14	0.29	0.58	1.16	1.30	1.38	1.52	1.52	1.52	1.52	1.74	1.88	2.68	3.33	3.69
1990	1,425	0.14	0.35	0.77	0.98	1.05	1.19	1.19	1.19	1.26	1.54	1.89	2.60	3.16	3.51	3.58
1991	1,462	0.14	0.27	0.41	0.48	0.62	0.62	0.62	0.68	1.03	1.37	2.05	2.60	2.87	2.94	3.01
1992	1,614	0.00	0.06	0.12	0.25	0.25	0.25	0.31	0.56	0.81	1.30	1.80	2.04	2.11	2.23	2.42
1993	1,766	0.00	0.06	0.17	0.17	0.23	0.40	0.74	1.08	1.64	2.27	2.49	2.49	2.60	2.72	2.77
1994	1,849	0.05	0.16	0.16	0.27	0.38	0.81	1.08	1.62	2.22	2.49	2.54	2.60	2.76	2.81	3.19
1995	2,057	0.05	0.05	0.10	0.19	0.68	0.92	1.60	2.19	2.43	2.48	2.53	2.67	2.72	3.11	3.50
1996	2,256	0.00	0.04	0.09	0.49	0.80	1.51	2.04	2.26	2.35	2.39	2.53	2.53	2.93	3.41	3.46
1997	2,507	0.08	0.16	0.48	0.80	1.36	2.07	2.43	2.51	2.55	2.67	2.67	3.07	3.51	3.55	3.67
1998	2,789	0.14	0.43	0.79	1.36	2.37	2.80	2.98	3.08	3.16	3.16	3.62	4.20	4.27	4.41	
1999	2,892	0.17	0.48	0.93	1.90	2.35	2.49	2.59	2.73	2.73	3.25	3.91	3.98	4.11		
2000	2,953	0.24	0.61	1.56	2.03	2.13	2.27	2.40	2.40	2.98	3.66	3.73	3.89			
2001	3,030	0.26	1.25	1.68	1.85	2.01	2.15	2.15	2.67	3.40	3.43	3.60				
2002	3,137	0.41	0.77	0.89	1.02	1.08	1.08	1.63	2.30	2.33	2.45					
2003	3,054	0.10	0.20	0.29	0.33	0.33	0.85	1.57	1.60	1.70						
2004	3,171	0.03	0.09	0.13	0.13	0.63	1.26	1.32	1.42							
2005	3,282	0.03	0.06	0.06	0.61	1.19	1.28	1.37								
2006	3,304	0.00	0.00	0.48	0.91	1.00	1.09									
2007	3,381	0.00	0.47	0.92	1.09	1.18										
2008	3,382	0.41	0.80	0.95	1.06											
2009	3,426	0.32	0.44	0.53												
2010	3,263	0.00	0.03													
2011	3,331	0.03														
Summary statistics																
Marginal average		0.12	0.21	0.24	0.30	0.31	0.31	0.29	0.28	0.27	0.28	0.26	0.22	0.22	0.22	0.24
Cumulative average		0.12	0.33	0.57	0.86	1.17	1.47	1.76	2.03	2.30	2.57	2.82	3.04	3.25	3.46	3.69
Standard deviation		0.12	0.28	0.40	0.51	0.60	0.65	0.68	0.72	0.78	0.82	0.85	0.84	0.78	0.70	0.63
Median		0.08	0.24	0.45	0.81	1.08	1.32	1.71	2.23	2.43	2.66	2.79	2.94	3.09	3.37	3.67
Minimum		0.00	0.00	0.06	0.13	0.23	0.25	0.31	0.56	0.81	1.30	1.74	1.88	2.11	2.23	2.42
Maximum		0.41	1.25	1.68	2.03	2.37	2.80	2.98	3.08	3.59	4.12	4.39	4.67	4.67	4.85	4.85

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 32

Static Pool Cumulative Global Corporate Default Rates Among All Speculative-Grade Ratings (1981-2011) (%)

		--Time horizon (years)--														
Year	No. issuers	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1981	321	0.62	4.67	7.79	10.90	13.08	17.76	18.69	19.63	21.50	23.68	27.41	28.66	30.22	30.53	30.84
1982	340	4.41	7.06	10.29	12.65	17.06	17.65	18.53	20.00	22.06	26.18	27.35	28.82	29.12	29.41	29.41
1983	341	2.93	5.57	8.80	14.08	15.25	17.89	19.65	21.70	26.69	27.86	29.33	29.62	29.91	29.91	30.21
1984	368	3.26	7.34	13.86	15.22	18.21	20.65	23.37	27.45	28.80	30.43	30.71	30.98	30.98	31.25	31.25
1985	418	4.31	11.24	13.16	16.75	19.62	22.49	26.79	27.99	29.19	29.43	29.90	29.90	29.90	29.90	30.62
1986	530	5.66	7.74	11.32	13.96	17.55	21.89	23.21	24.72	25.28	25.66	26.04	26.42	26.60	27.17	27.92
1987	681	2.79	6.75	10.57	15.12	20.85	23.05	24.96	25.55	26.28	26.73	27.02	27.17	27.75	28.93	30.40
1988	756	3.84	7.94	13.62	21.03	23.15	25.00	25.53	26.59	26.98	27.51	28.04	28.70	30.42	31.88	33.20
1989	751	4.66	11.72	21.17	23.44	25.43	26.23	27.16	27.56	28.36	29.43	29.96	31.56	32.89	34.22	34.89
1990	692	8.09	18.06	21.53	23.55	24.42	25.58	25.87	27.02	28.32	28.90	30.64	32.23	34.10	34.97	35.26
1991	589	11.04	15.96	17.49	18.51	20.03	20.37	21.56	22.92	23.43	24.96	26.83	29.20	30.22	30.73	31.07
1992	526	6.08	7.98	9.13	11.22	11.79	13.12	14.64	15.21	17.30	19.77	22.62	23.57	24.14	24.33	24.33
1993	561	2.50	4.28	7.66	8.56	9.98	11.23	11.94	14.08	16.76	19.43	20.50	21.21	21.57	22.10	22.46
1994	713	2.10	5.89	7.29	8.70	10.10	12.06	15.01	18.23	20.90	22.02	22.72	23.14	23.70	23.98	25.11
1995	824	3.52	5.22	6.80	8.50	10.68	13.59	18.20	21.48	22.94	23.67	24.27	24.76	25.00	25.85	27.91
1996	887	1.80	3.72	6.20	9.24	12.06	16.35	20.29	22.10	22.89	23.56	24.01	24.46	25.37	27.17	27.62
1997	1,000	2.00	5.20	9.00	13.10	18.40	22.70	25.00	25.80	26.50	27.20	27.70	28.80	30.70	30.90	31.00
1998	1,315	3.65	9.13	14.52	21.52	26.24	29.13	30.27	31.03	31.86	32.32	33.31	35.06	35.21	35.29	
1999	1,659	5.55	11.87	20.25	26.40	29.66	30.92	31.71	32.43	32.85	34.12	36.17	36.53	36.65		
2000	1,774	6.14	15.05	21.76	25.42	27.11	28.07	28.80	29.37	30.72	33.31	33.65	33.82			
2001	1,776	9.74	17.57	22.07	23.70	24.83	25.56	26.13	27.53	30.29	30.74	30.91				
2002	1,696	9.32	14.39	16.39	17.45	18.34	18.93	20.58	23.88	24.41	24.65					
2003	1,788	4.98	6.99	8.11	9.12	9.68	11.41	15.04	15.72	16.00						
2004	1,905	2.05	3.31	4.30	4.93	6.82	10.97	11.76	12.18							
2005	2,086	1.44	2.40	3.26	5.51	10.35	11.46	12.08								
2006	2,222	1.13	2.12	5.00	10.94	12.29	13.19									
2007	2,348	0.89	4.17	11.33	13.12	14.10										

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2008	2,469	3.56	11.83	14.01	14.90											
2009	2,343	9.52	12.04	13.06												
2010	2,234	2.82	4.39													
2011	2,516	1.71														
Summary statistics																
Marginal average		4.21	4.20	3.82	3.20	2.65	2.28	1.96	1.72	1.60	1.49	1.29	1.11	1.02	0.92	0.96
Cumulative average		4.21	8.23	11.74	14.56	16.82	18.72	20.31	21.68	22.93	24.08	25.06	25.89	26.65	27.33	28.03
Standard deviation		2.81	4.56	5.54	6.10	6.34	6.15	5.85	5.45	4.72	4.03	3.93	4.04	4.04	3.72	3.46
Median		3.56	7.20	11.32	14.02	17.55	19.65	21.56	24.30	26.28	26.96	27.70	28.81	29.91	29.91	30.40
Minimum		0.62	2.12	3.26	4.93	6.82	10.97	11.76	12.18	16.00	19.43	20.50	21.21	21.57	22.10	22.46
Maximum		11.04	18.06	22.07	26.40	29.66	30.92	31.71	32.43	32.85	34.12	36.17	36.53	36.65	35.29	35.26

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 33

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--One-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	87.19	8.69	0.54	0.05	0.08	0.03	0.05	0.00	3.37
	(9.11)	(9.10)	(0.87)	(0.31)	(0.25)	(0.20)	(0.40)	(0.00)	(2.58)
AA	0.56	86.32	8.30	0.54	0.06	0.08	0.02	0.02	4.09
	(0.55)	(4.94)	(4.01)	(0.73)	(0.25)	(0.25)	(0.07)	(0.07)	(1.92)
A	0.04	1.91	87.27	5.44	0.38	0.16	0.02	0.08	4.72
	(0.13)	(1.15)	(3.49)	(2.10)	(0.49)	(0.36)	(0.07)	(0.11)	(1.92)
BBB	0.01	0.12	3.64	84.87	3.91	0.64	0.15	0.24	6.42
	(0.07)	(0.23)	(2.31)	(4.64)	(1.84)	(1.03)	(0.24)	(0.27)	(1.82)
BB	0.02	0.04	0.16	5.24	75.87	7.19	0.75	0.90	9.84
	(0.06)	(0.16)	(0.39)	(2.37)	(4.97)	(4.70)	(0.92)	(1.05)	(2.85)
B	0.00	0.04	0.13	0.22	5.57	73.42	4.42	4.48	11.72
	(0.00)	(0.13)	(0.38)	(0.34)	(2.52)	(5.30)	(2.57)	(3.32)	(3.02)
CCC/C	0.00	0.00	0.17	0.26	0.78	13.67	43.93	26.82	14.37
	(0.00)	(0.00)	(0.71)	(1.02)	(1.30)	(8.59)	(12.79)	(12.68)	(7.32)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 34

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--Two-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	76.39	14.99	1.45	0.11	0.19	0.05	0.11	0.03	6.67
	(11.36)	(11.87)	(1.46)	(0.35)	(0.44)	(0.27)	(0.48)	(0.20)	(4.56)
AA	0.98	74.79	14.50	1.41	0.20	0.17	0.02	0.07	7.86
	(0.66)	(7.44)	(5.62)	(1.15)	(0.45)	(0.34)	(0.07)	(0.12)	(3.16)
A	0.05	3.41	76.42	9.30	0.89	0.37	0.06	0.19	9.32
	(0.10)	(1.86)	(5.13)	(2.82)	(0.92)	(0.59)	(0.11)	(0.20)	(2.99)
BBB	0.02	0.25	6.63	72.20	6.15	1.38	0.28	0.68	12.42
	(0.14)	(0.33)	(3.52)	(7.05)	(2.51)	(1.53)	(0.35)	(0.60)	(2.77)
BB	0.01	0.06	0.39	9.01	57.57	10.72	1.21	2.75	18.28
	(0.07)	(0.17)	(0.81)	(3.67)	(5.86)	(3.70)	(1.05)	(2.34)	(3.69)
B	0.00	0.05	0.23	0.55	9.21	53.70	5.00	10.18	21.09
	(0.00)	(0.16)	(0.55)	(0.61)	(3.48)	(6.63)	(2.65)	(5.77)	(4.88)
CCC/C	0.00	0.00	0.28	0.74	1.30	16.58	22.19	36.45	22.46
	(0.00)	(0.00)	(0.78)	(2.16)	(1.93)	(7.87)	(12.33)	(13.92)	(10.15)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 35

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--Three-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	66.82	19.93	2.42	0.33	0.17	0.08	0.11	0.14	9.99
	(11.61)	(11.67)	(1.67)	(0.83)	(0.45)	(0.35)	(0.51)	(0.39)	(5.50)
AA	1.29	65.24	18.95	2.24	0.36	0.27	0.03	0.15	11.47
	(0.79)	(8.34)	(5.83)	(1.41)	(0.66)	(0.53)	(0.08)	(0.19)	(4.32)
A	0.08	4.42	67.45	11.90	1.40	0.57	0.12	0.33	13.74
	(0.11)	(2.38)	(5.96)	(2.83)	(1.14)	(0.82)	(0.16)	(0.26)	(3.69)

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BBB	0.03	0.38	8.67	62.12	7.36	2.07	0.36	1.19	17.83
	(0.10)	(0.54)	(4.11)	(7.92)	(2.67)	(1.76)	(0.50)	(0.86)	(3.40)
BB	0.01	0.07	0.65	11.17	44.28	12.13	1.35	4.97	25.36
	(0.09)	(0.23)	(1.10)	(4.30)	(5.86)	(3.83)	(1.09)	(3.44)	(4.01)
B	0.01	0.04	0.32	1.00	10.71	39.49	4.54	15.25	28.63
	(0.12)	(0.16)	(0.80)	(0.99)	(3.64)	(6.30)	(2.40)	(6.82)	(6.03)
CCC/C	0.00	0.00	0.26	0.88	1.86	15.18	11.62	42.69	27.52
	(0.00)	(0.00)	(0.86)	(2.34)	(3.41)	(7.59)	(11.50)	(14.23)	(11.60)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 36

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--Five-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	52.33	24.52	4.96	0.87	0.17	0.15	0.09	0.35	16.56
	(9.54)	(9.66)	(2.63)	(1.80)	(0.44)	(0.46)	(0.33)	(0.61)	(6.65)
AA	1.62	50.95	24.17	3.94	0.59	0.41	0.05	0.35	17.91
	(0.92)	(6.79)	(4.64)	(1.79)	(0.71)	(0.72)	(0.12)	(0.38)	(4.86)
A	0.10	5.55	54.06	15.07	2.19	0.85	0.18	0.67	21.33
	(0.11)	(2.58)	(6.84)	(2.33)	(1.30)	(1.15)	(0.22)	(0.43)	(4.15)
BBB	0.04	0.65	10.60	48.20	7.86	2.77	0.44	2.39	27.06
	(0.11)	(0.68)	(4.34)	(7.93)	(2.47)	(1.83)	(0.58)	(1.30)	(4.36)
BB	0.01	0.09	1.30	12.49	28.25	11.25	1.42	9.16	36.03
	(0.08)	(0.28)	(1.27)	(4.09)	(5.24)	(3.20)	(1.47)	(4.61)	(4.21)
B	0.02	0.04	0.41	1.93	10.77	22.87	2.93	21.41	39.62
	(0.27)	(0.14)	(1.18)	(1.55)	(2.85)	(5.81)	(1.42)	(7.97)	(6.27)
CCC/C	0.00	0.00	0.24	0.91	3.16	12.38	3.28	45.93	34.10
	(0.00)	(0.00)	(0.84)	(4.15)	(3.22)	(5.56)	(7.92)	(13.97)	(12.18)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 37

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--Seven-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	41.59	26.98	7.35	1.68	0.21	0.12	0.12	0.49	21.44
	(7.09)	(7.21)	(2.40)	(2.15)	(0.50)	(0.40)	(0.35)	(0.75)	(7.09)
AA	1.69	40.17	27.20	5.21	0.78	0.38	0.04	0.52	24.01
	(1.03)	(4.70)	(3.76)	(1.62)	(0.72)	(0.59)	(0.10)	(0.55)	(4.70)
A	0.10	5.80	44.69	16.77	2.77	1.01	0.17	1.13	27.56
	(0.14)	(2.08)	(6.30)	(1.78)	(1.40)	(1.25)	(0.23)	(0.54)	(3.69)
BBB	0.05	0.90	10.95	39.19	7.69	2.87	0.41	3.65	34.29
	(0.17)	(0.56)	(3.85)	(6.29)	(0.91)	(1.30)	(0.52)	(1.60)	(3.56)
BB	0.00	0.09	1.76	12.19	19.58	9.72	1.10	12.99	42.57
	(0.00)	(0.30)	(1.38)	(4.39)	(4.52)	(2.77)	(0.99)	(4.93)	(3.76)
B	0.01	0.03	0.60	2.42	8.92	13.77	1.78	26.29	46.18
	(0.23)	(0.15)	(1.01)	(2.00)	(2.32)	(3.58)	(0.93)	(7.48)	(6.02)
CCC/C	0.00	0.00	0.42	1.32	3.62	8.36	1.46	48.82	36.00
	(0.00)	(0.00)	(0.93)	(4.69)	(2.40)	(4.23)	(4.45)	(13.14)	(11.04)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 38

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--10-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	28.49	28.06	10.26	3.32	0.17	0.07	0.03	0.67	28.93
	(5.86)	(6.77)	(2.19)	(2.38)	(0.31)	(0.24)	(0.14)	(0.81)	(7.26)
AA	1.44	28.33	28.75	7.18	1.03	0.44	0.03	0.77	32.02
	(0.81)	(4.24)	(3.02)	(1.40)	(0.88)	(0.38)	(0.11)	(0.71)	(4.18)
A	0.15	5.51	34.29	17.56	3.15	1.07	0.14	1.90	36.23
	(0.19)	(1.80)	(3.85)	(2.18)	(0.60)	(0.93)	(0.18)	(0.78)	(3.85)
BBB	0.03	1.14	10.17	29.54	7.30	2.91	0.30	5.77	42.83
	(0.15)	(0.74)	(3.77)	(4.00)	(1.14)	(1.10)	(0.24)	(1.55)	(3.02)
BB	0.02	0.08	2.02	10.83	12.70	7.45	0.69	18.78	47.42
	(0.10)	(0.23)	(1.38)	(3.74)	(3.45)	(2.73)	(0.53)	(4.33)	(4.02)
B	0.00	0.02	0.67	2.53	6.18	7.37	0.88	33.43	48.92

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	(0.00)	(0.08)	(0.95)	(2.06)	(1.43)	(2.57)	(0.80)	(5.87)	(5.27)
CCC/C	0.00	0.00	0.30	0.79	3.35	2.85	0.30	56.69	35.73
	(0.00)	(0.00)	(0.92)	(1.83)	(4.09)	(3.16)	(0.63)	(10.56)	(11.36)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 39

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--15-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	16.28	25.65	15.93	3.08	0.48	0.31	0.00	0.97	37.31
	(3.87)	(4.78)	(2.78)	(0.83)	(0.50)	(0.56)	(0.00)	(0.96)	(4.21)
AA	1.18	17.52	25.76	9.60	1.36	0.77	0.05	1.18	42.57
	(0.85)	(2.57)	(2.64)	(2.35)	(0.89)	(0.46)	(0.10)	(0.68)	(3.47)
A	0.15	4.67	24.74	16.60	3.27	1.27	0.08	2.77	46.44
	(0.26)	(1.37)	(2.44)	(0.97)	(1.03)	(0.62)	(0.11)	(0.81)	(3.34)
BBB	0.00	1.18	8.55	21.99	5.30	2.58	0.17	7.88	52.36
	(0.00)	(0.41)	(2.89)	(2.00)	(1.01)	(1.31)	(0.22)	(0.97)	(2.52)
BB	0.00	0.15	2.42	9.01	6.52	4.45	0.40	21.73	55.32
	(0.00)	(0.29)	(1.33)	(2.57)	(1.42)	(2.13)	(0.49)	(4.49)	(2.09)
B	0.00	0.00	0.65	3.37	3.77	3.43	0.63	34.42	53.73
	(0.00)	(0.00)	(0.65)	(1.40)	(1.18)	(1.26)	(0.43)	(3.90)	(4.81)
CCC/C	0.00	0.00	0.90	1.44	2.15	1.08	0.36	56.01	38.06
	(0.00)	(0.00)	(2.94)	(1.48)	(4.62)	(1.15)	(0.91)	(10.38)	(11.26)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 40

Average Multiyear Global Corporate Transition Matrix (1981-2011)

(%)	--20-year transition rates--								
From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
AAA	7.84	20.79	19.97	3.34	0.75	0.89	0.00	1.64	44.79
	(2.37)	(4.30)	(5.20)	(1.94)	(0.60)	(0.60)	(0.00)	(1.15)	(6.94)
AA	1.00	9.70	20.92	12.63	1.56	0.89	0.10	2.25	50.96
	(0.80)	(1.85)	(3.23)	(1.77)	(0.34)	(0.53)	(0.19)	(1.00)	(2.54)
A	0.19	3.03	17.67	15.27	3.50	1.97	0.13	4.75	53.50
	(0.25)	(1.08)	(2.30)	(1.37)	(0.69)	(0.70)	(0.16)	(1.09)	(1.90)
BBB	0.00	0.94	7.28	18.52	4.16	1.90	0.18	10.51	56.51
	(0.00)	(0.51)	(1.23)	(2.49)	(1.13)	(0.97)	(0.30)	(1.69)	(2.51)
BB	0.00	0.11	2.03	7.02	3.55	3.29	0.25	25.77	57.98
	(0.00)	(0.23)	(0.91)	(2.03)	(1.40)	(0.93)	(0.35)	(4.90)	(3.21)
B	0.00	0.00	0.45	3.28	2.84	1.88	0.32	37.76	53.48
	(0.00)	(0.00)	(0.30)	(0.87)	(0.72)	(0.82)	(0.38)	(4.33)	(5.10)
CCC/C	0.00	0.00	0.24	0.97	2.66	0.72	0.00	58.21	37.20
	(0.00)	(0.00)	(0.53)	(0.90)	(5.26)	(0.83)	(0.00)	(9.53)	(11.74)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 41

Average Multiyear Global Corporate Transition Matrices (1981-2011)--All Financials (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
One-year									
AAA	87.36	8.99	0.38	0.08	0.08	0.04	0.08	0.00	2.97
	(12.20)	(11.86)	(1.30)	(0.42)	(0.46)	(0.25)	(0.49)	(0.00)	(2.68)
AA	0.53	86.10	8.80	0.42	0.03	0.03	0.04	0.04	4.00
	(0.85)	(5.47)	(4.99)	(1.03)	(0.07)	(0.07)	(0.29)	(0.10)	(2.16)
A	0.03	2.77	87.35	4.14	0.31	0.09	0.02	0.14	5.17
	(0.36)	(1.79)	(4.19)	(3.28)	(0.88)	(0.18)	(0.04)	(0.18)	(2.51)
BBB	0.00	0.30	5.07	82.71	3.27	0.62	0.20	0.39	7.44
	(0.00)	(1.00)	(3.25)	(6.31)	(4.51)	(1.84)	(0.44)	(1.01)	(2.79)
BB	0.00	0.15	0.26	7.26	73.50	5.01	1.14	1.07	11.61
	(0.00)	(0.33)	(1.33)	(6.48)	(9.63)	(4.50)	(2.73)	(1.82)	(6.63)
B	0.00	0.06	0.17	0.46	8.85	72.09	3.16	3.50	11.72
	(0.00)	(0.24)	(1.36)	(2.94)	(6.31)	(13.95)	(6.84)	(6.51)	(7.71)
CCC/C	0.00	0.00	0.00	0.00	1.96	15.69	44.77	17.97	19.61
	(0.00)	(0.00)	(0.00)	(0.00)	(5.80)	(13.79)	(31.30)	(24.54)	(16.53)
Three-year									
AAA	67.45	20.69	1.76	0.35	0.18	0.09	0.18	0.22	9.09

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	(15.32)	(13.95)	(3.13)	(1.98)	(0.60)	(0.38)	(0.66)	(0.54)	(5.75)
AA	1.31	65.06	19.79	1.97	0.15	0.20	0.05	0.24	11.23
	(1.48)	(8.56)	(7.79)	(2.24)	(0.39)	(0.53)	(0.09)	(0.31)	(4.40)
A	0.06	6.52	67.95	8.17	1.12	0.35	0.16	0.62	15.06
	(0.45)	(3.24)	(7.37)	(3.24)	(2.03)	(1.12)	(0.38)	(0.62)	(5.55)
BBB	0.00	0.87	12.66	57.79	4.53	1.20	0.44	1.82	20.69
	(0.00)	(2.34)	(6.05)	(7.31)	(3.82)	(2.75)	(1.46)	(1.82)	(5.55)
BB	0.00	0.22	1.18	15.64	40.81	6.93	1.39	4.40	29.44
	(0.00)	(0.57)	(2.56)	(7.91)	(15.09)	(4.99)	(2.47)	(6.14)	(12.62)
B	0.00	0.00	0.49	2.46	17.59	39.34	2.60	9.57	27.94
	(0.00)	(0.00)	(2.02)	(5.03)	(8.04)	(18.68)	(4.46)	(12.76)	(14.21)
CCC/C	0.00	0.00	0.39	0.78	2.71	19.38	12.79	23.26	40.70
	(0.00)	(0.00)	(9.28)	(3.10)	(5.77)	(13.49)	(17.46)	(30.01)	(28.75)
10-year									
AAA	27.73	29.51	10.41	2.67	0.11	0.11	0.06	0.95	28.45
	(6.73)	(10.96)	(5.57)	(4.46)	(0.31)	(0.33)	(0.21)	(1.39)	(9.91)
AA	1.46	32.29	28.33	4.84	0.30	0.30	0.05	1.18	31.25
	(1.29)	(7.74)	(7.31)	(2.42)	(0.32)	(0.36)	(0.08)	(2.48)	(5.83)
A	0.16	8.86	35.90	8.19	1.94	0.25	0.22	2.34	42.13
	(0.86)	(3.43)	(3.74)	(3.27)	(0.68)	(0.79)	(0.21)	(1.58)	(5.44)
BBB	0.00	3.61	12.50	22.55	2.83	0.89	0.47	6.02	51.13
	(0.00)	(5.58)	(3.66)	(6.85)	(1.90)	(1.17)	(0.92)	(2.25)	(5.18)
BB	0.00	0.28	5.71	13.95	5.06	3.56	0.19	15.07	56.18
	(0.00)	(0.77)	(4.40)	(4.82)	(2.60)	(3.19)	(0.25)	(10.94)	(11.37)
B	0.00	0.00	3.10	8.61	10.15	6.37	0.34	21.51	49.91
	(0.00)	(0.00)	(3.93)	(8.91)	(7.65)	(6.88)	(5.39)	(15.95)	(15.46)
CCC/C	0.00	0.00	0.87	0.00	5.22	6.09	0.00	44.35	43.48
	(0.00)	(0.00)	(10.66)	(0.00)	(7.04)	(5.59)	(0.00)	(32.85)	(35.12)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 42

Average Multiyear Global Corporate Transition Matrices (1981-2011)--Insurance (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
One-year									
AAA	87.89	9.99	0.29	0.00	0.07	0.07	0.15	0.00	1.53
	(18.93)	(18.74)	(1.51)	(0.00)	(0.29)	(0.50)	(1.00)	(0.00)	(2.08)
AA	0.69	86.85	7.85	0.46	0.06	0.06	0.09	0.06	3.90
	(3.81)	(6.96)	(5.51)	(1.05)	(0.14)	(0.12)	(1.80)	(0.13)	(2.49)
A	0.02	3.15	88.17	3.70	0.32	0.11	0.02	0.21	4.31
	(0.06)	(8.86)	(10.67)	(5.32)	(2.24)	(0.25)	(0.05)	(0.35)	(3.58)
BBB	0.00	0.19	5.87	82.38	3.06	0.57	0.48	0.29	7.16
	(0.00)	(2.29)	(5.50)	(6.13)	(5.11)	(2.17)	(1.59)	(2.01)	(5.31)
BB	0.00	0.17	0.69	9.12	71.77	3.79	1.72	1.03	11.70
	(0.00)	(1.50)	(3.19)	(12.46)	(16.20)	(6.79)	(4.23)	(3.86)	(9.21)
B	0.00	0.33	0.66	0.66	10.26	70.53	3.97	3.31	10.26
	(0.00)	(1.38)	(6.10)	(4.69)	(12.66)	(20.37)	(6.40)	(8.49)	(10.64)
CCC/C	0.00	0.00	0.00	0.00	2.94	10.29	44.12	26.47	16.18
	(0.00)	(0.00)	(0.00)	(0.00)	(6.88)	(21.22)	(38.83)	(31.88)	(18.77)
Three-year									
AAA	67.64	24.22	1.87	0.00	0.15	0.15	0.30	0.37	5.31
	(19.87)	(18.00)	(2.60)	(0.00)	(0.61)	(0.74)	(1.22)	(0.93)	(5.74)
AA	1.68	66.48	17.66	2.27	0.25	0.31	0.09	0.37	10.88
	(7.50)	(12.79)	(8.31)	(2.39)	(0.88)	(0.56)	(0.19)	(0.47)	(5.19)
A	0.10	7.40	69.55	6.95	1.11	0.25	0.23	0.94	13.47
	(0.19)	(13.82)	(15.81)	(5.62)	(5.02)	(3.45)	(0.22)	(3.05)	(6.99)
BBB	0.00	0.69	15.11	57.67	4.56	0.98	0.75	1.61	18.63
	(0.00)	(4.37)	(6.70)	(10.65)	(5.16)	(2.23)	(2.90)	(4.24)	(7.46)
BB	0.00	0.21	2.69	18.43	39.34	4.55	2.48	4.35	27.95
	(0.00)	(1.55)	(6.37)	(15.85)	(25.13)	(7.45)	(6.53)	(8.43)	(15.96)
B	0.00	0.00	2.78	5.16	17.46	41.27	1.98	9.52	21.83
	(0.00)	(0.00)	(10.15)	(13.45)	(16.17)	(25.23)	(2.64)	(13.44)	(11.55)
CCC/C	0.00	0.00	1.82	1.82	7.27	10.91	18.18	36.36	23.64
	(0.00)	(0.00)	(18.57)	(6.19)	(10.67)	(10.31)	(23.36)	(36.61)	(33.14)
10-year									
AAA	28.48	36.45	11.45	2.47	0.18	0.18	0.09	1.56	19.14

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	(18.95)	(13.05)	(8.87)	(3.93)	(0.49)	(0.52)	(0.33)	(2.03)	(11.91)
AA	2.22	32.38	27.21	4.94	0.55	0.55	0.09	1.62	30.44
	(4.89)	(9.33)	(5.79)	(3.86)	(1.10)	(0.56)	(0.14)	(2.17)	(6.75)
A	0.49	8.72	35.86	8.77	2.52	0.27	0.66	3.95	38.76
	(5.96)	(11.05)	(8.89)	(6.51)	(2.48)	(0.39)	(0.47)	(4.32)	(11.52)
BBB	0.00	5.20	11.01	29.51	3.52	0.46	0.61	8.72	40.98
	(0.00)	(9.54)	(7.04)	(12.53)	(5.66)	(0.53)	(1.12)	(5.80)	(6.25)
BB	0.00	1.37	9.59	13.70	8.68	4.11	0.00	28.77	33.79
	(0.00)	(2.62)	(11.43)	(10.49)	(9.46)	(5.25)	(0.00)	(12.47)	(12.67)
B	0.00	0.00	10.38	20.75	11.32	2.83	1.89	21.70	31.13
	(0.00)	(0.00)	(13.62)	(22.59)	(16.07)	(10.83)	(8.68)	(18.73)	(13.85)
CCC/C	0.00	0.00	4.17	0.00	0.00	0.00	0.00	70.83	25.00
	(0.00)	(0.00)	(21.32)	(0.00)	(0.00)	(0.00)	(0.00)	(44.82)	(32.17)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 43

Average Multiyear Global Corporate Transition Matrices (1981-2011)--Financial Institutions (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
One-year									
AAA	86.63	7.60	0.51	0.20	0.10	0.00	0.00	0.00	4.96
	(12.40)	(12.05)	(1.54)	(1.02)	(0.94)	(0.00)	(0.00)	(0.00)	(4.43)
AA	0.39	85.38	9.72	0.39	0.00	0.00	0.00	0.03	4.10
	(0.94)	(6.66)	(6.37)	(1.18)	(0.00)	(0.00)	(0.00)	(0.08)	(2.54)
A	0.03	2.51	86.79	4.44	0.30	0.07	0.01	0.09	5.76
	(0.44)	(2.11)	(5.33)	(3.89)	(1.04)	(0.18)	(0.06)	(0.20)	(3.40)
BBB	0.00	0.35	4.70	82.87	3.37	0.63	0.07	0.44	7.57
	(0.00)	(1.23)	(3.89)	(8.23)	(5.35)	(2.23)	(0.41)	(0.97)	(3.13)
BB	0.00	0.14	0.14	6.75	73.97	5.35	0.98	1.08	11.59
	(0.00)	(0.35)	(1.76)	(5.87)	(9.57)	(6.22)	(2.80)	(1.47)	(7.56)
B	0.00	0.00	0.07	0.42	8.55	72.41	2.99	3.54	12.02
	(0.00)	(0.00)	(1.20)	(4.72)	(6.42)	(15.57)	(8.56)	(10.97)	(8.02)
CCC/C	0.00	0.00	0.00	0.00	1.68	17.23	44.96	15.55	20.59
	(0.00)	(0.00)	(0.00)	(0.00)	(6.67)	(12.88)	(32.30)	(17.97)	(15.77)
Three-year									
AAA	67.17	15.61	1.61	0.86	0.22	0.00	0.00	0.00	14.53
	(16.43)	(14.99)	(3.82)	(2.59)	(0.91)	(0.00)	(0.00)	(0.00)	(7.95)
AA	0.95	63.71	21.83	1.69	0.06	0.09	0.00	0.12	11.55
	(1.11)	(9.86)	(9.50)	(2.54)	(0.36)	(0.60)	(0.00)	(0.29)	(5.15)
A	0.03	5.95	66.92	8.95	1.13	0.40	0.11	0.42	16.08
	(0.55)	(4.10)	(8.69)	(4.18)	(2.09)	(0.91)	(0.42)	(0.60)	(6.46)
BBB	0.00	0.94	11.58	57.84	4.51	1.30	0.31	1.91	21.60
	(0.00)	(2.08)	(7.63)	(9.80)	(5.19)	(3.62)	(1.55)	(2.29)	(5.95)
BB	0.00	0.22	0.77	14.89	41.20	7.56	1.10	4.41	29.84
	(0.00)	(0.79)	(2.54)	(6.81)	(12.96)	(5.86)	(2.83)	(6.85)	(13.62)
B	0.00	0.00	0.00	1.88	17.62	38.92	2.74	9.58	29.26
	(0.00)	(0.00)	(0.00)	(5.83)	(12.98)	(20.08)	(6.64)	(18.14)	(17.22)
CCC/C	0.00	0.00	0.00	0.49	1.48	21.67	11.33	19.70	45.32
	(0.00)	(0.00)	(0.00)	(2.06)	(6.67)	(14.95)	(23.36)	(20.66)	(27.20)
10-year									
AAA	26.56	18.75	8.81	2.98	0.00	0.00	0.00	0.00	42.90
	(10.22)	(9.31)	(7.61)	(5.85)	(0.00)	(0.00)	(0.00)	(0.00)	(11.43)
AA	0.70	32.20	29.46	4.74	0.05	0.05	0.00	0.74	32.06
	(1.14)	(10.53)	(10.10)	(3.46)	(0.13)	(0.26)	(0.00)	(3.21)	(6.48)
A	0.00	8.93	35.92	7.90	1.65	0.24	0.00	1.54	43.80
	(0.00)	(3.77)	(4.55)	(4.37)	(1.27)	(0.97)	(0.00)	(1.93)	(6.43)
BBB	0.00	3.07	13.01	20.19	2.60	1.04	0.42	5.10	54.58
	(0.00)	(4.83)	(4.04)	(6.93)	(2.16)	(1.66)	(1.31)	(3.04)	(6.58)
BB	0.00	0.00	4.71	14.02	4.12	3.42	0.24	11.54	61.96
	(0.00)	(0.00)	(3.37)	(5.40)	(3.13)	(4.21)	(0.28)	(12.29)	(14.38)
B	0.00	0.00	1.47	5.89	9.89	7.16	0.00	21.47	54.11
	(0.00)	(0.00)	(2.78)	(11.64)	(8.13)	(21.33)	(0.00)	(26.71)	(24.51)
CCC/C	0.00	0.00	0.00	0.00	6.59	7.69	0.00	37.36	48.35
	(0.00)	(0.00)	(0.00)	(0.00)	(9.49)	(6.79)	(0.00)	(23.40)	(37.09)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

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Table 44

Average Multiyear Global Corporate Transition Matrices (1981-2011)--Nonfinancials (%)

From/to	AAA	AA	A	BBB	BB	B	CCC/C	D	NR
One-year									
AAA	86.88	8.15	0.82	0.00	0.07	0.00	0.00	0.00	4.08
	(8.07)	(6.67)	(1.50)	(0.00)	(0.30)	(0.00)	(0.00)	(0.00)	(4.15)
AA	0.58	86.57	7.71	0.68	0.10	0.15	0.00	0.00	4.20
	(0.75)	(5.75)	(3.86)	(1.03)	(0.32)	(0.36)	(0.00)	(0.00)	(2.64)
A	0.04	1.28	87.21	6.38	0.43	0.21	0.02	0.03	4.40
	(0.13)	(1.33)	(3.97)	(2.32)	(0.54)	(0.45)	(0.09)	(0.08)	(2.27)
BBB	0.01	0.06	3.14	85.63	4.13	0.65	0.13	0.18	6.05
	(0.07)	(0.19)	(2.51)	(5.11)	(1.82)	(1.04)	(0.25)	(0.30)	(2.06)
BB	0.02	0.02	0.14	4.87	76.31	7.60	0.68	0.86	9.51
	(0.07)	(0.17)	(0.41)	(2.37)	(5.36)	(4.94)	(0.72)	(1.12)	(2.96)
B	0.00	0.03	0.12	0.20	5.24	73.56	4.54	4.58	11.72
	(0.00)	(0.13)	(0.39)	(0.28)	(2.58)	(5.18)	(2.75)	(3.44)	(3.07)
CCC/C	0.00	0.00	0.20	0.30	0.60	13.36	43.80	28.18	13.56
	(0.00)	(0.00)	(0.81)	(1.12)	(1.29)	(8.72)	(12.92)	(13.18)	(7.78)
Three-year									
AAA	65.74	18.64	3.55	0.30	0.15	0.08	0.00	0.00	11.55
	(10.67)	(9.76)	(3.15)	(1.14)	(0.43)	(0.27)	(0.00)	(0.00)	(6.73)
AA	1.28	65.44	17.99	2.53	0.60	0.34	0.02	0.03	11.75
	(0.94)	(10.02)	(6.00)	(1.80)	(0.93)	(0.55)	(0.07)	(0.10)	(4.84)
A	0.09	3.00	67.11	14.42	1.58	0.72	0.10	0.14	12.85
	(0.12)	(2.81)	(6.32)	(3.69)	(1.14)	(0.95)	(0.17)	(0.20)	(3.47)
BBB	0.04	0.22	7.34	63.57	8.30	2.35	0.33	0.97	16.88
	(0.12)	(0.41)	(4.67)	(8.88)	(2.58)	(1.78)	(0.43)	(1.00)	(3.50)
BB	0.02	0.04	0.56	10.39	44.89	13.05	1.34	5.07	24.64
	(0.10)	(0.25)	(1.11)	(4.29)	(6.67)	(4.15)	(1.03)	(3.55)	(4.50)
B	0.01	0.05	0.31	0.87	10.06	39.51	4.72	15.79	28.69
	(0.12)	(0.17)	(0.85)	(0.94)	(3.59)	(6.12)	(2.56)	(6.96)	(6.34)
CCC/C	0.00	0.00	0.24	0.89	1.73	14.53	11.44	45.68	25.49
	(0.00)	(0.00)	(0.52)	(2.47)	(3.68)	(7.72)	(12.41)	(15.84)	(11.45)
10-year									
AAA	29.65	25.86	10.03	4.30	0.25	0.00	0.00	0.25	29.65
	(10.13)	(6.13)	(4.91)	(3.45)	(0.64)	(0.00)	(0.00)	(0.52)	(7.01)
AA	1.42	24.83	29.12	9.26	1.68	0.55	0.02	0.41	32.71
	(1.01)	(8.55)	(4.37)	(3.61)	(1.24)	(0.53)	(0.12)	(0.53)	(5.18)
A	0.15	3.78	33.45	22.42	3.78	1.49	0.09	1.67	33.17
	(0.15)	(2.75)	(4.41)	(4.60)	(0.77)	(0.92)	(0.18)	(0.78)	(2.78)
BBB	0.04	0.50	9.57	31.37	8.46	3.44	0.25	5.71	40.66
	(0.17)	(0.52)	(4.79)	(4.68)	(1.46)	(1.43)	(0.29)	(1.70)	(3.53)
BB	0.03	0.05	1.49	10.38	13.80	8.01	0.77	19.31	46.16
	(0.12)	(0.23)	(1.29)	(4.31)	(3.88)	(3.05)	(0.58)	(4.88)	(4.92)
B	0.00	0.02	0.50	2.12	5.91	7.44	0.91	34.26	48.85
	(0.00)	(0.08)	(1.02)	(1.84)	(1.56)	(2.59)	(0.68)	(6.18)	(5.74)
CCC/C	0.00	0.00	0.22	0.89	3.11	2.44	0.33	58.27	34.74
	(0.00)	(0.00)	(0.44)	(2.00)	(4.04)	(3.19)	(0.72)	(12.62)	(12.67)

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Appendix II: Additional Tables

Table 45

Initial-To-Last Transition Rates By Rating Modifier: Nonfinancials (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	142	4.23	2.11	4.23	5.63	6.34	6.34	4.23	1.41	0.70	0.70	0.00	0.00	0.00	0.70	0.70	0.00	0.00	2.11	60.56
AA+	69	2.90	1.45	5.80	7.25	5.80	4.35	11.59	2.90	2.90	0.00	0.00	2.90	1.45	0.00	1.45	0.00	0.00	1.45	47.83
AA	278	0.36	0.72	2.88	4.32	2.52	5.40	9.35	4.68	5.04	2.88	0.72	0.72	0.00	0.00	0.36	0.00	0.36	2.52	57.19
AA-	204	0.49	0.00	0.00	7.84	6.86	8.82	13.24	6.37	2.94	2.45	0.49	0.00	0.49	0.49	0.00	0.00	0.98	1.47	47.06
A+	304	0.66	0.00	0.00	3.62	10.53	6.25	10.20	7.24	3.62	3.62	1.64	0.66	0.33	1.32	0.33	0.00	0.00	3.29	46.71
A	689	0.00	0.00	0.15	0.58	3.05	9.29	7.26	6.97	7.11	2.76	1.16	1.31	0.44	0.00	1.02	0.44	0.00	4.93	53.56
A-	454	0.00	0.00	0.22	0.22	1.32	5.95	16.52	8.81	7.49	4.41	1.54	1.54	0.66	0.44	0.44	0.44	0.22	3.30	46.48
BBB+	481	0.00	0.00	0.00	0.21	0.42	3.12	4.99	19.33	12.89	5.41	2.08	1.46	1.04	0.42	0.00	0.21	0.42	4.16	43.87
BBB	748	0.00	0.13	0.00	0.00	0.40	1.34	2.94	5.88	16.84	7.22	2.14	1.07	1.34	0.80	0.27	0.80	0.27	6.82	51.74
BBB-	676	0.00	0.00	0.15	0.00	0.00	0.44	1.48	2.66	8.14	17.60	3.55	2.66	1.33	1.18	1.48	0.44	0.00	9.32	49.56

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BB+	427	0.00	0.00	0.00	0.00	0.00	0.23	1.41	0.94	3.75	8.43	14.29	4.45	3.04	2.11	1.64	2.11	0.47	10.30	46.84
BB	703	0.00	0.00	0.00	0.00	0.14	0.14	0.28	1.71	0.71	3.70	5.12	12.94	4.98	2.56	1.99	1.28	0.43	17.07	46.94
BB-	1,307	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.23	1.07	1.22	2.83	3.98	12.70	3.75	3.14	0.77	0.54	22.57	46.98
B+	2,113	0.00	0.00	0.00	0.00	0.05	0.00	0.14	0.09	0.38	0.57	0.80	1.51	2.98	13.35	4.69	1.66	0.80	26.36	46.62
B	1,566	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.19	0.13	0.38	0.51	0.70	1.85	4.02	22.41	3.19	1.85	22.03	42.59
B-	636	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.16	0.00	0.63	0.31	0.63	1.26	1.73	5.82	16.19	3.14	25.79	44.18
CCC/C	353	0.00	0.00	0.00	0.00	0.00	0.28	0.28	0.28	0.57	0.28	0.57	0.57	1.70	2.55	5.10	8.78	12.46	32.86	33.71

Note: Initial-to-last transition rates are calculated based on the original rating vis-à-vis the last rating for rated entities across all time horizons. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 46

Initial-To-Last Transition Rates By Rating Modifier: Insurance (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	139	0.00	11.51	8.63	20.86	5.76	5.04	5.04	0.72	1.44	0.00	0.72	0.00	0.00	0.00	1.44	0.00	0.00	2.88	35.97
AA+	46	0.00	2.17	4.35	13.04	13.04	10.87	6.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.17	0.00	2.17	45.65
AA	137	0.00	0.73	2.92	17.52	8.76	8.03	7.30	0.73	0.00	2.19	0.00	0.00	0.00	0.00	1.46	0.00	0.00	5.84	44.53
AA-	115	0.00	0.00	2.61	21.74	12.17	8.70	9.57	2.61	0.87	0.87	0.87	0.00	0.87	0.00	0.87	0.00	0.00	0.87	37.39
A+	153	0.00	0.65	0.65	4.58	23.53	11.11	5.88	4.58	1.31	0.00	0.00	0.65	0.00	0.00	0.00	0.00	0.65	1.96	44.44
A	177	0.00	1.13	0.56	2.82	9.60	24.86	14.12	4.52	2.26	0.56	0.56	0.00	0.56	0.00	0.00	0.00	0.56	5.08	32.77
A-	189	0.00	0.00	0.00	0.53	3.17	14.29	31.75	6.88	2.12	1.59	0.00	0.53	0.00	0.00	0.53	0.00	0.53	4.23	33.86
BBB+	102	0.00	0.00	0.00	0.00	0.98	1.96	16.67	25.49	8.82	4.90	0.98	0.00	0.00	0.00	0.00	0.00	0.00	2.94	37.25
BBB	123	0.00	0.00	0.00	0.00	1.63	1.63	5.69	15.45	22.76	6.50	2.44	1.63	0.00	0.00	0.00	0.00	0.00	6.50	35.77
BBB-	83	0.00	0.00	1.20	0.00	2.41	2.41	1.20	6.02	7.23	20.48	7.23	1.20	0.00	0.00	0.00	0.00	0.00	3.61	46.99
BB+	33	0.00	0.00	0.00	0.00	0.00	0.00	6.06	3.03	0.00	15.15	27.27	3.03	0.00	0.00	0.00	0.00	0.00	9.09	36.36
BB	39	0.00	0.00	0.00	0.00	0.00	0.00	2.56	0.00	2.56	10.26	2.56	10.26	2.56	0.00	0.00	0.00	0.00	7.69	61.54
BB-	22	0.00	0.00	0.00	0.00	0.00	0.00	4.55	0.00	0.00	9.09	4.55	4.55	18.18	0.00	0.00	4.55	0.00	9.09	45.45
B+	26	0.00	0.00	0.00	0.00	3.85	0.00	0.00	3.85	7.69	3.85	3.85	7.69	0.00	19.23	7.69	0.00	3.85	7.69	30.77
B	31	0.00	0.00	0.00	0.00	3.23	0.00	3.23	3.23	0.00	0.00	3.23	9.68	0.00	6.45	19.35	3.23	0.00	16.13	32.26
B-	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.67	0.00	0.00	8.33	25.00	50.00
CCC/C	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.00	20.00	0.00	40.00	20.00

Note: Initial-to-last transition rates are calculated based on the original rating vis-à-vis the last rating for rated entities across all time horizons. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 47

Initial-To-Last Transition Rates By Rating Modifier: Financial Institutions (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	130	5.38	16.15	0.77	2.31	8.46	6.92	1.54	1.54	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00	0.00	0.77	55.38
AA+	49	4.08	6.12	6.12	8.16	6.12	10.20	2.04	0.00	2.04	2.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.06
AA	141	0.00	2.13	4.26	14.89	6.38	7.09	1.42	3.55	1.42	1.42	0.71	0.00	0.00	0.00	0.00	0.00	0.00	2.84	53.90
AA-	187	0.53	0.00	1.60	10.16	11.76	13.37	6.42	1.60	2.67	0.00	0.53	0.00	0.53	0.00	0.00	0.00	0.00	2.14	48.66
A+	210	0.00	0.00	0.00	6.19	14.76	10.00	4.29	2.86	1.43	1.43	0.95	0.95	0.95	0.00	0.00	0.00	0.00	0.95	55.24
A	275	0.00	0.00	0.00	4.00	5.09	12.73	6.55	5.45	4.36	1.82	0.73	0.36	0.00	0.00	0.73	0.36	0.36	0.73	56.73
A-	234	0.00	0.00	0.43	0.85	5.56	12.39	15.81	10.68	5.98	1.71	1.71	2.14	0.00	0.00	0.00	0.00	0.00	1.28	41.45
BBB+	197	0.00	0.00	0.00	0.51	3.55	6.60	6.60	13.20	7.61	4.57	3.05	0.51	0.51	0.51	0.00	0.00	0.00	3.55	49.24
BBB	232	0.00	0.00	0.00	0.86	2.16	1.72	5.17	7.76	18.97	3.88	0.43	1.29	0.86	0.00	0.00	0.43	0.00	4.31	52.16
BBB-	237	0.00	0.00	0.00	0.00	1.69	1.27	3.38	5.91	9.28	20.68	2.11	0.42	0.00	2.11	0.00	0.00	2.11	8.44	42.62
BB+	112	0.00	0.00	0.00	0.00	0.00	0.89	0.89	1.79	11.61	10.71	13.39	2.68	2.68	0.89	0.00	0.00	0.00	10.71	43.75
BB	138	0.00	0.00	0.00	0.00	0.00	0.72	0.72	0.00	5.07	7.97	5.07	13.04	2.17	0.72	0.72	1.45	0.00	9.42	52.90
BB-	171	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.75	0.58	0.58	2.92	6.43	15.20	4.09	4.68	0.00	0.00	13.45	50.29
B+	149	0.00	0.00	0.00	0.00	0.00	0.00	0.67	0.67	1.34	0.67	4.03	5.37	5.37	22.15	4.03	2.01	0.67	10.74	42.28
B	166	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.20	0.00	0.60	1.20	2.41	4.82	19.88	8.43	0.00	15.06	46.39
B-	77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.30	0.00	2.60	1.30	2.60	5.19	15.58	16.88	1.30	6.49	46.75
CCC/C	82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.22	0.00	1.22	2.44	3.66	8.54	6.10	10.98	20.73	45.12

Note: Initial-to-last transition rates are calculated based on the original rating vis-à-vis the last rating for rated entities across all time horizons. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 48

Initial-To-Last Default Rates By Rating Category For Broad Sectors (%)

	--Nonfinancials--		--Insurance--		--Financial institutions--	
	Issuer count	Default rate (%)	Issuer count	Default rate (%)	Issuer count	Default rate (%)
AAA	142	2.11	139	2.88	130	0.77
AA+	69	1.45	46	2.17	49	0.00
AA	278	2.52	137	5.84	141	2.84
AA-	204	1.47	115	0.87	187	2.14
A+	304	3.29	153	1.96	210	0.95
A	689	4.93	177	5.08	275	0.73
A-	454	3.30	189	4.23	234	1.28

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BBB+	481	4.16	102	2.94	197	3.55
BBB	748	6.82	123	6.50	232	4.31
BBB-	676	9.32	83	3.61	237	8.44
BB+	427	10.30	33	9.09	112	10.71
BB	703	17.07	39	7.69	138	9.42
BB-	1,307	22.57	22	9.09	171	13.45
B+	2,113	26.36	26	7.69	149	10.74
B	1,566	22.03	31	16.13	166	15.06
B-	636	25.79	12	25.00	77	6.49
CCC/C	353	32.86	5	40.00	82	20.73

Note: Initial-to-last default rates are calculated based on the original rating vis-à-vis the last rating for rated entities across all time horizons.
Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 49

Default Rates By Rating Category By Broad Sectors (%)

	--Nonfinancials--			--Insurance--			--Financial institutions--		
Rating	One-year (2011 pool)	Three-year (2009 pool)	10-year (2002 pool)	One-year (2011 pool)	Three-year (2009 pool)	10-year (2002 pool)	One-year (2011 pool)	Three-year (2009 pool)	10-year (2002 pool)
AAA	0.00	0.00	0.00	0.00	0.00	1.82	0.00	0.00	0.00
AA+	0.00	0.00	0.00	0.00	0.00	2.78	0.00	0.00	0.00
AA	0.00	0.00	0.00	0.00	0.00	1.09	0.00	0.00	0.00
AA-	0.00	0.00	0.00	0.00	0.00	1.33	0.00	0.00	0.00
A+	0.00	0.00	0.00	0.00	0.00	2.27	0.00	0.70	2.06
A	0.00	0.00	0.89	0.00	0.76	1.25	0.00	0.61	0.92
A-	0.00	0.00	0.00	0.00	0.75	2.94	0.00	0.00	2.47
BBB+	0.00	0.00	4.11	0.00	0.00	4.55	0.00	1.72	2.41
BBB	0.00	0.00	3.74	0.00	1.72	0.00	0.00	2.68	2.67
BBB-	0.00	0.00	7.90	0.00	1.85	9.52	0.98	7.53	6.06
BB+	0.00	0.00	8.67	0.00	0.00	0.00	0.00	2.44	5.00
BB	0.00	1.28	13.19	0.00	0.00	0.00	0.00	5.88	2.56
BB-	0.00	2.02	21.07	0.00	0.00	14.29	0.00	1.39	0.00
B+	0.22	8.18	23.24	9.09	0.00	60.00	0.00	13.16	6.25
B	0.78	13.71	31.58	8.33	0.00	0.00	3.33	15.15	11.54
B-	4.26	29.48	49.12	0.00	14.29	0.00	2.50	11.11	7.69
CCC/C	16.81	63.86	65.52	16.67	37.50	75.00	7.69	33.33	31.58

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 50

Corporate Transition Matrix--One Year Ended Dec. 31, 2011: Nonfinancials (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	13	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA+	6	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA	41	0.00	0.00	51.22	29.27	12.20	0.00	0.00	2.44	0.00	0.00	0.00	0.00	0.00	2.44	0.00	0.00	0.00	0.00	2.44
AA-	46	0.00	0.00	0.00	89.13	8.70	2.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A+	85	0.00	0.00	0.00	4.71	88.24	5.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.18
A	205	0.00	0.00	0.00	0.49	3.90	82.44	6.83	1.46	0.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.90
A-	274	0.00	0.00	0.00	0.00	0.00	1.82	86.13	6.57	0.73	1.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.65
BBB+	301	0.00	0.00	0.00	0.00	0.00	0.33	6.64	80.73	7.64	1.00	0.00	0.00	0.00	0.33	0.00	0.00	0.00	0.00	3.32
BBB	374	0.00	0.00	0.00	0.00	0.00	0.00	0.80	11.23	81.02	3.21	0.27	0.00	0.27	0.00	0.00	0.27	0.00	0.00	2.94
BBB-	357	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	10.92	77.31	4.76	0.84	0.28	0.00	0.28	0.00	0.00	0.00	5.32
BB+	193	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.55	14.51	66.84	6.22	2.07	0.00	0.52	0.00	0.52	0.00	7.77
BB	249	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.40	20.08	62.25	6.02	0.40	0.40	0.40	0.00	0.00	9.64
BB-	327	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.00	0.31	1.53	18.04	62.69	4.89	3.36	0.00	0.00	0.00	8.56
B+	447	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.67	1.12	13.65	61.52	7.83	2.24	0.67	0.22	12.08
B	514	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	0.00	0.00	0.39	0.78	10.51	65.95	5.84	2.92	0.78	12.65
B-	258	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.00	0.39	0.78	14.34	58.53	9.69	4.26	11.63
CCC/C	119	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84	2.52	18.49	47.90	16.81	13.45

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 51

Corporate Transition Matrix--One Year Ended Dec. 31, 2011: Insurance (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	8	12.50	87.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA+	19	0.00	68.42	0.00	31.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA	32	0.00	0.00	62.50	28.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.38

show

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue E2
Schedule 14.4
Attachment

AA-	94	0.00	0.00	4.26	79.79	7.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.51
A+	123	0.00	0.00	0.00	7.32	78.86	7.32	0.81	0.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.88
A	127	0.00	0.00	0.00	0.00	1.57	84.25	5.51	1.57	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.30
A-	159	0.00	0.00	0.00	0.00	0.00	5.03	84.91	6.92	0.00	0.63	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.89
BBB+	73	0.00	0.00	0.00	0.00	0.00	0.00	1.37	84.93	5.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.22
BBB	56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.14	78.57	8.93	0.00	0.00	0.00	0.00	3.57	0.00	0.00	0.00	1.79
BBB-	49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.12	77.55	6.12	0.00	2.04	0.00	0.00	0.00	2.04	0.00	6.12
BB+	22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.09	63.64	4.55	0.00	0.00	0.00	0.00	0.00	0.00	22.73
BB	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.00	75.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BB-	15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	46.67	0.00	0.00	6.67	0.00	0.00	26.67
B+	11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.09	72.73	0.00	0.00	0.00	9.09	9.09
B	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.33	66.67	0.00	0.00	8.33	16.67
B-	3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.67	33.33	0.00	0.00
CCC/C	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.67	66.67	16.67	0.00

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 52

Corporate Transition Matrix--One Year Ended Dec. 31, 2011: Financial Institutions (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	30	36.67	53.33	3.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.67
AA+	11	0.00	90.91	9.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA	47	0.00	0.00	25.53	59.57	6.38	0.00	0.00	2.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.38
AA-	67	0.00	0.00	1.49	52.24	32.84	4.48	1.49	1.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.97
A+	149	0.00	0.00	0.00	7.38	58.39	22.15	0.67	1.34	0.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.40
A	138	0.00	0.00	0.00	0.00	11.59	53.62	22.46	6.52	0.72	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.35
A-	127	0.00	0.00	0.00	0.00	0.79	14.96	48.82	13.39	11.81	3.15	3.15	1.57	0.00	0.00	0.00	0.00	0.00	0.00	2.36
BBB+	99	0.00	0.00	0.00	0.00	0.00	0.00	13.13	67.68	8.08	5.05	1.01	1.01	0.00	0.00	0.00	0.00	0.00	0.00	4.04
BBB	119	0.00	0.00	0.00	0.00	0.00	0.00	0.84	6.72	73.95	6.72	3.36	2.52	0.84	0.00	0.00	0.00	0.00	0.00	5.04
BBB-	102	0.00	0.00	0.00	0.00	0.00	1.96	0.00	0.98	17.65	64.71	2.94	1.96	0.00	0.00	0.00	0.00	0.00	0.98	8.82
BB+	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.22	4.44	20.00	48.89	2.22	4.44	4.44	0.00	0.00	2.22	0.00	11.11
BB	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.72	5.17	24.14	43.10	5.17	0.00	0.00	1.72	5.17	0.00	13.79
BB-	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.64	0.00	4.92	13.11	49.18	6.56	9.84	1.64	0.00	0.00	13.11
B+	51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.84	17.65	58.82	3.92	3.92	0.00	0.00	7.84
B	60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.67	21.67	51.67	5.00	3.33	3.33	13.33
B-	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.50	2.50	35.00	42.50	5.00	2.50	10.00
CCC/C	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.69	0.00	30.77	38.46	7.69	15.38

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 53

Corporate Transition Matrix--Three Years Ended Dec. 31, 2011: Nonfinancials (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	14	64.29	14.29	7.14	7.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.14
AA+	13	23.08	23.08	30.77	7.69	7.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.69
AA	57	0.00	0.00	24.56	26.32	7.02	8.77	1.75	1.75	3.51	0.00	0.00	0.00	0.00	1.75	0.00	0.00	0.00	0.00	24.56
AA-	62	0.00	0.00	1.61	53.23	25.81	4.84	1.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.90
A+	87	0.00	0.00	0.00	5.75	57.47	16.09	2.30	2.30	0.00	1.15	0.00	1.15	0.00	1.15	1.15	0.00	0.00	0.00	11.49
A	215	0.00	0.00	0.00	0.00	6.05	55.81	15.81	6.51	2.79	1.40	0.00	0.00	0.00	0.00	0.00	0.47	0.00	0.00	11.16
A-	282	0.00	0.00	0.00	0.35	0.35	6.74	61.70	17.38	1.77	0.71	0.00	0.35	0.00	0.00	0.35	0.00	0.00	0.00	10.28
BBB+	301	0.00	0.00	0.00	0.00	0.00	0.66	13.29	49.17	19.93	3.99	1.33	0.66	0.33	0.00	0.00	0.00	0.00	0.00	10.63
BBB	371	0.00	0.00	0.00	0.00	0.00	0.27	1.08	15.63	53.91	13.21	3.23	1.35	0.00	0.27	0.27	0.00	0.27	0.00	10.51
BBB-	309	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.27	15.86	49.19	9.39	4.53	0.97	1.62	0.00	1.29	0.00	0.00	14.89
BB+	187	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.60	1.60	22.46	34.22	10.70	3.74	1.07	1.07	0.53	0.00	0.00	22.99
BB	234	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	1.28	5.56	20.94	32.48	9.83	2.99	1.71	0.00	0.43	1.28	23.08
BB-	347	0.00	0.00	0.00	0.00	0.00	0.00	0.58	0.29	0.29	0.86	4.90	13.26	31.70	12.97	7.78	4.32	1.15	2.02	19.88
B+	379	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.00	0.00	1.32	5.01	9.50	31.13	15.30	5.54	0.53	8.18	23.22
B	423	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.24	0.00	0.24	0.24	1.18	4.02	8.51	30.50	8.04	4.02	13.71	29.08
B-	251	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	3.98	12.75	19.52	7.97	29.48	25.90
CCC/C	166	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.00	0.60	0.00	1.81	3.61	3.01	5.42	63.86	21.08

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 54

Corporate Transition Matrix--Three Years Ended Dec. 31, 2011: Insurance (%)

show

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	27	3.70	70.37	0.00	25.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA+	8	0.00	12.50	25.00	62.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

AA	71	0.00	0.00	25.35	42.25	4.23	2.82	5.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00	0.00	0.00	18.31
AA-	79	0.00	0.00	5.06	50.63	21.52	8.86	1.27	0.00	1.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.39
A+	108	0.00	0.00	0.00	6.48	55.56	13.89	5.56	0.93	0.00	0.00	0.00	0.00	0.93	0.00	0.00	0.00	0.00	0.00	16.67
A	131	0.00	0.00	0.00	2.29	12.98	50.38	16.03	3.05	2.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	0.76	11.45
A-	134	0.00	0.00	0.00	0.75	0.00	12.69	60.45	10.45	2.24	1.49	0.75	0.00	0.00	0.75	0.75	0.75	0.00	0.75	8.21
BBB+	78	0.00	0.00	0.00	0.00	0.00	0.00	17.95	51.28	14.10	2.56	0.00	0.00	1.28	1.28	0.00	0.00	0.00	0.00	11.54
BBB	58	0.00	0.00	0.00	0.00	0.00	1.72	0.00	15.52	43.10	10.34	3.45	0.00	0.00	0.00	1.72	0.00	0.00	1.72	22.41
BBB-	54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.56	7.41	53.70	5.56	1.85	1.85	0.00	0.00	0.00	0.00	1.85	22.22
BB+	18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.11	44.44	0.00	0.00	0.00	0.00	0.00	5.56	0.00	38.89
BB	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.52	9.52	19.05	0.00	0.00	0.00	0.00	4.76	0.00	57.14
BB-	11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.18	45.45	9.09	0.00	0.00	0.00	0.00	0.00	27.27
B+	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.22	11.11	44.44	11.11	0.00	0.00	0.00	11.11
B	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.69	15.38	46.15	0.00	0.00	0.00	30.77
B-	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.29	0.00	14.29	0.00	14.29	57.14
CCC/C	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.50	37.50	50.00

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 55

Corporate Transition Matrix--Three Years Ended Dec. 31, 2011: Financial Institutions (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	32	25.00	56.25	3.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.13	0.00	0.00	0.00	0.00	0.00	0.00	12.50
AA+	16	12.50	37.50	6.25	18.75	6.25	0.00	0.00	6.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.50
AA	59	0.00	3.39	13.56	44.07	13.56	3.39	0.00	0.00	0.00	1.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.34
AA-	105	0.00	0.00	1.90	27.62	28.57	18.10	1.90	3.81	0.00	0.00	0.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.14
A+	143	0.00	0.00	0.00	7.69	43.36	15.38	7.69	2.80	2.80	0.70	0.70	0.70	0.00	0.00	0.00	0.00	0.00	0.70	17.48
A	165	0.00	0.00	0.00	0.61	7.88	36.97	19.39	10.91	3.64	1.82	3.03	1.82	0.61	0.00	0.00	0.00	0.00	0.61	12.73
A-	126	0.00	0.00	0.00	0.00	0.79	12.70	28.57	15.08	15.08	0.79	0.00	1.59	0.79	0.00	0.79	0.00	1.59	0.00	22.22
BBB+	116	0.00	0.00	0.00	0.00	0.86	0.00	11.21	31.03	21.55	8.62	2.59	1.72	0.00	0.86	0.00	0.00	2.59	1.72	17.24
BBB	112	0.00	0.00	0.00	0.00	0.89	0.00	0.89	10.71	41.96	13.39	4.46	0.89	0.89	0.00	0.89	0.89	0.00	2.68	21.43
BBB-	93	0.00	0.00	0.00	0.00	0.00	1.08	0.00	2.15	13.98	44.09	4.30	0.00	2.15	2.15	0.00	0.00	0.00	7.53	22.58
BB+	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.44	12.20	14.63	24.39	9.76	7.32	7.32	0.00	0.00	0.00	2.44	19.51
BB	34	0.00	0.00	0.00	0.00	0.00	0.00	2.94	0.00	0.00	11.76	14.71	17.65	5.88	8.82	2.94	0.00	0.00	5.88	29.41
BB-	72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.11	19.44	22.22	12.50	0.00	1.39	0.00	1.39	31.94
B+	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.63	2.63	7.89	26.32	10.53	2.63	2.63	13.16	31.58
B	33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.09	12.12	15.15	18.18	3.03	15.15	27.27
B-	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.56	52.78	22.22	0.00	11.11	8.33
CCC/C	15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.67	6.67	33.33	53.33

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 56

Corporate Transition Matrix--10 Years Ended Dec. 31, 2011: Nonfinancials (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	34	20.59	2.94	17.65	14.71	8.82	5.88	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.47
AA+	22	0.00	9.09	4.55	13.64	4.55	18.18	4.55	4.55	0.00	0.00	0.00	4.55	0.00	0.00	0.00	0.00	0.00	0.00	36.36
AA	53	1.89	0.00	9.43	22.64	11.32	9.43	9.43	5.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.19
AA-	116	1.72	0.00	1.72	11.21	14.66	14.66	16.38	4.31	0.86	3.45	0.86	0.00	0.00	0.86	0.86	0.00	0.00	0.00	28.45
A+	146	0.00	0.00	0.68	1.37	10.96	19.86	14.38	10.96	6.16	6.16	0.00	0.00	0.68	0.68	0.68	0.00	0.00	0.00	27.40
A	225	0.00	0.00	0.00	0.89	8.00	13.78	18.67	12.44	9.33	3.11	0.44	1.33	0.89	0.00	1.33	0.00	0.00	0.89	28.89
A-	279	0.00	0.00	0.00	0.00	1.08	5.38	23.66	17.56	16.49	5.02	1.43	0.36	0.72	0.36	1.08	0.00	0.36	0.00	26.52
BBB+	341	0.00	0.00	0.29	0.00	0.59	2.35	7.33	19.94	14.37	7.92	3.23	2.35	0.59	1.17	0.59	0.00	0.29	4.11	34.90
BBB	348	0.00	0.00	0.00	0.00	0.00	1.15	2.30	8.05	18.97	14.66	3.74	3.16	2.01	2.01	1.15	0.86	0.29	3.74	37.93
BBB-	291	0.00	0.00	0.34	0.00	0.00	0.69	3.44	5.84	11.34	9.28	6.19	3.78	3.78	1.03	1.72	3.44	0.00	7.90	41.24
BB+	150	0.00	0.00	0.00	0.00	0.00	0.00	1.33	3.33	7.33	6.67	8.00	6.00	2.67	4.00	4.67	3.33	2.00	8.67	42.00
BB	235	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.28	2.98	4.68	7.23	7.23	8.94	3.83	4.26	2.98	0.43	13.19	42.98
BB-	261	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	1.53	5.75	4.60	7.66	5.75	4.60	2.30	0.77	21.07	45.21
B+	370	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.54	0.54	1.89	2.70	5.41	5.14	5.14	1.62	0.81	23.24	52.70
B	190	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.53	2.11	1.58	1.58	3.16	5.79	2.63	0.00	31.58	51.05
B-	114	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.75	0.88	0.88	0.88	1.75	2.63	1.75	0.00	49.12	40.35
CCC/C	145	0.00	0.00	0.00	0.00	0.00	0.69	0.00	0.00	0.69	0.69	0.69	0.00	0.00	0.69	1.38	0.69	0.00	65.52	28.97

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 57

show

Corporate Transition Matrix--10 Years Ended Dec. 31, 2011: Insurance (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	55	1.82	30.91	7.27	20.00	3.64	1.82	1.82	0.00	1.82	0.00	0.00	0.00	1.82	0.00	1.82	0.00	0.00	1.82	25.45

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Exhibit I
Issue E2
Schedule 14.4
Attachment

AA+	36	0.00	2.78	13.89	16.67	11.11	8.33	8.33	0.00	0.00	0.00	0.00	0.00	0.00	2.78	0.00	0.00	0.00	2.78	33.33
AA	92	0.00	1.09	5.43	29.35	10.87	9.78	2.17	0.00	0.00	0.00	0.00	0.00	0.00	1.09	0.00	1.09	1.09	1.09	36.96
AA-	75	0.00	0.00	5.33	14.67	14.67	9.33	17.33	4.00	1.33	1.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.33	30.67
A+	88	0.00	0.00	0.00	10.23	14.77	17.05	12.50	3.41	3.41	1.14	0.00	0.00	1.14	0.00	0.00	0.00	1.14	2.27	32.95
A	80	0.00	0.00	0.00	2.50	12.50	20.00	18.75	8.75	3.75	0.00	0.00	0.00	1.25	0.00	0.00	0.00	1.25	1.25	30.00
A-	68	0.00	0.00	0.00	0.00	2.94	10.29	23.53	8.82	0.00	2.94	1.47	0.00	0.00	0.00	2.94	0.00	1.47	2.94	42.65
BBB+	22	0.00	0.00	0.00	0.00	4.55	9.09	9.09	9.09	18.18	13.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.55	31.82
BBB	33	0.00	0.00	0.00	3.03	0.00	0.00	18.18	12.12	12.12	0.00	6.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.48
BBB-	21	0.00	0.00	0.00	0.00	4.76	0.00	0.00	0.00	4.76	33.33	9.52	4.76	0.00	0.00	0.00	0.00	0.00	9.52	33.33
BB+	3	0.00	0.00	0.00	0.00	33.33	0.00	0.00	0.00	0.00	33.33	33.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BB	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.00	12.50	12.50	0.00	0.00	0.00	0.00	0.00	0.00	50.00
BB-	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.29	85.71
B+	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	40.00
B	2	0.00	0.00	0.00	0.00	0.00	0.00	50.00	0.00	0.00	0.00	50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
B-	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCC/C	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	75.00	25.00

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 58

Corporate Transition Matrix--10 Years Ended Dec. 31, 2011: Financial Institutions (%)

Rating	No. issuers	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	33	12.12	51.52	3.03	0.00	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.30
AA+	16	12.50	25.00	12.50	0.00	0.00	18.75	0.00	6.25	6.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.75
AA	59	0.00	0.00	0.00	10.17	20.34	8.47	5.08	3.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.54
AA-	93	1.08	0.00	2.15	21.51	25.81	8.60	5.38	3.23	2.15	1.08	1.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.96
A+	97	0.00	0.00	0.00	12.37	17.53	6.19	6.19	6.19	3.09	2.06	2.06	1.03	2.06	0.00	1.03	0.00	0.00	2.06	38.14
A	109	0.00	0.00	0.00	7.34	6.42	22.02	7.34	5.50	8.26	2.75	0.92	0.00	0.00	0.00	0.92	0.00	0.00	0.92	37.61
A-	81	0.00	0.00	1.23	1.23	9.88	12.35	8.64	9.88	7.41	4.94	6.17	3.70	1.23	0.00	0.00	0.00	0.00	2.47	30.86
BBB+	83	0.00	0.00	0.00	1.20	6.02	7.23	7.23	4.82	6.02	2.41	2.41	0.00	0.00	1.20	0.00	0.00	3.61	2.41	55.42
BBB	75	0.00	0.00	0.00	1.33	1.33	1.33	12.00	9.33	14.67	8.00	1.33	0.00	0.00	0.00	0.00	0.00	1.33	2.67	46.67
BBB-	66	0.00	0.00	0.00	0.00	3.03	1.52	6.06	7.58	9.09	9.09	0.00	0.00	0.00	4.55	0.00	0.00	1.52	6.06	51.52
BB+	40	0.00	0.00	0.00	0.00	7.50	10.00	0.00	5.00	5.00	7.50	2.50	0.00	0.00	0.00	0.00	0.00	0.00	5.00	57.50
BB	39	0.00	0.00	0.00	0.00	0.00	2.56	0.00	10.26	7.69	15.38	0.00	0.00	0.00	2.56	0.00	0.00	0.00	2.56	58.97
BB-	33	0.00	0.00	0.00	0.00	0.00	0.00	3.03	3.03	3.03	0.00	0.00	3.03	0.00	3.03	3.03	3.03	0.00	0.00	78.79
B+	32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.38	0.00	3.13	0.00	6.25	3.13	12.50	0.00	3.13	0.00	6.25	56.25
B	26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.85	0.00	3.85	15.38	3.85	0.00	11.54	61.54
B-	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.69	23.08	0.00	0.00	7.69	0.00	0.00	7.69	53.85
CCC/C	19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.26	5.26	10.53	10.53	0.00	0.00	31.58	36.84

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 59

One-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Nonfinancials (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	86.88	3.11	4.30	0.74	0.30	0.22	0.30	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	4.08
AA+	3.20	79.94	7.66	3.34	0.70	0.70	0.28	0.14	0.28	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.62
AA	0.42	1.16	81.88	6.95	2.43	1.41	0.46	0.56	0.11	0.11	0.07	0.04	0.04	0.04	0.00	0.04	0.00	0.00	4.30
AA-	0.00	0.08	3.59	77.66	9.68	3.06	0.69	0.25	0.20	0.16	0.08	0.00	0.00	0.04	0.20	0.04	0.00	0.00	4.25
A+	0.00	0.05	0.56	3.26	77.99	9.41	2.85	0.82	0.33	0.08	0.15	0.10	0.03	0.15	0.08	0.03	0.00	0.05	4.05
A	0.06	0.03	0.27	0.40	4.09	78.66	6.75	3.22	1.25	0.30	0.18	0.18	0.15	0.18	0.00	0.01	0.01	0.01	4.24
A-	0.05	0.00	0.07	0.07	0.40	5.31	76.60	8.81	2.56	0.56	0.16	0.16	0.13	0.16	0.02	0.02	0.05	0.04	4.83
BBB+	0.00	0.02	0.05	0.02	0.18	0.94	6.05	74.03	9.58	2.08	0.43	0.46	0.18	0.31	0.13	0.02	0.05	0.13	5.33
BBB	0.01	0.00	0.03	0.01	0.09	0.43	1.16	6.38	75.68	6.52	1.51	0.82	0.34	0.28	0.19	0.05	0.05	0.16	6.28
BBB-	0.02	0.00	0.00	0.07	0.07	0.20	0.38	1.26	8.38	71.92	5.70	2.72	1.08	0.44	0.38	0.22	0.33	0.27	6.55
BB+	0.09	0.00	0.00	0.00	0.00	0.09	0.06	0.62	2.25	11.83	62.50	6.89	3.40	1.30	0.86	0.18	0.44	0.30	9.20
BB	0.00	0.00	0.04	0.00	0.00	0.09	0.09	0.19	0.68	2.33	8.85	64.29	8.32	2.76	1.30	0.49	0.60	0.75	9.22
BB-	0.00	0.00	0.00	0.02	0.02	0.02	0.08	0.16	0.30	0.45	1.83	8.64	63.94	8.67	3.08	0.82	0.85	1.24	9.89
B+	0.00	0.01	0.00	0.05	0.00	0.05	0.08	0.06	0.07	0.07	0.29	1.42	6.90	65.18	7.94	2.56	1.92	2.51	10.89
B	0.00	0.00	0.02	0.00	0.00	0.07	0.07	0.04	0.09	0.02	0.20	0.37	1.46	8.15	58.62	8.15	5.32	5.59	11.84
B-	0.00	0.00	0.00	0.00	0.04	0.04	0.00	0.11	0.04	0.18	0.15	0.18	0.55	2.94	10.01	50.83	11.48	9.24	14.21
CCC/C	0.00	0.00	0.00	0.00	0.05	0.00	0.15	0.10	0.10	0.10	0.00	0.15	0.45	1.31	3.01	9.04	43.80	28.18	13.56

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 60

One-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Insurance (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	87.89	6.93	2.19	0.88	0.07	0.22	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07	0.00	0.15	0.00	1.53

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Issue E2
Schedule 14.4
Attachment

AA+	2.09	73.74	13.39	5.39	1.04	0.52	0.35	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.30
AA	0.59	1.12	79.34	9.61	3.16	1.32	0.59	0.20	0.33	0.00	0.07	0.07	0.00	0.00	0.00	0.00	0.20	0.07	3.36
AA-	0.21	0.29	4.37	76.36	10.82	1.65	0.86	0.29	0.21	0.00	0.00	0.00	0.00	0.07	0.07	0.00	0.00	0.07	4.73
A+	0.00	0.24	0.79	5.93	76.47	8.59	2.24	0.91	0.54	0.06	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.06	4.05
A	0.06	0.18	0.48	0.96	5.95	77.45	6.79	1.32	1.08	0.36	0.12	0.18	0.00	0.00	0.12	0.00	0.06	0.36	4.51
A-	0.00	0.07	0.14	0.35	1.18	7.40	78.27	5.05	1.66	0.55	0.14	0.21	0.21	0.14	0.07	0.00	0.00	0.21	4.36
BBB+	0.00	0.00	0.12	0.00	0.97	1.34	10.48	71.62	6.70	1.22	0.61	0.24	0.24	0.12	0.12	0.00	0.24	0.00	5.97
BBB	0.00	0.00	0.13	0.13	0.66	0.79	0.52	10.50	68.90	6.04	1.57	0.79	0.26	0.39	0.26	0.00	0.52	0.26	8.27
BBB-	0.00	0.00	0.20	0.00	0.00	0.20	0.39	1.57	10.18	70.65	5.48	0.78	0.59	0.59	0.39	0.00	0.78	0.78	7.44
BB+	0.00	0.00	0.00	0.00	0.00	0.75	0.75	0.37	1.87	10.49	64.04	3.00	4.49	1.50	0.37	0.37	0.75	1.50	9.74
BB	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.52	1.55	6.70	10.82	56.70	3.61	1.03	1.55	0.00	2.58	1.03	13.40
BB-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	0.00	0.83	8.33	16.67	48.33	5.00	0.83	3.33	2.50	0.00	13.33
B+	0.00	0.00	0.00	0.00	0.00	0.00	0.73	0.00	0.00	0.00	1.46	8.03	8.76	59.12	4.38	2.92	3.65	3.65	7.30
B	0.00	0.00	0.00	0.85	0.00	0.85	0.00	0.85	0.00	0.00	0.00	0.00	4.27	11.97	60.68	2.56	2.56	1.71	13.68
B-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.08	0.00	0.00	0.00	0.00	2.08	4.17	14.58	52.08	8.33	6.25	10.42
CCC/C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.47	1.47	1.47	2.94	5.88	44.12	26.47	16.18

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 61

One-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Financial Institutions (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	86.63	6.08	1.22	0.30	0.10	0.30	0.10	0.00	0.20	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.96
AA+	2.14	73.16	15.44	4.04	0.95	0.71	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.33
AA	0.39	1.77	75.96	11.48	4.08	1.39	0.15	0.46	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.16
AA-	0.00	0.05	4.86	76.28	10.40	3.24	0.57	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	4.23
A+	0.00	0.09	0.40	5.92	76.20	8.67	2.00	0.40	0.40	0.13	0.04	0.13	0.00	0.04	0.00	0.00	0.00	0.09	5.47
A	0.00	0.04	0.15	0.60	6.82	75.03	7.75	2.27	0.89	0.19	0.04	0.04	0.04	0.04	0.04	0.00	0.00	0.07	6.00
A-	0.10	0.00	0.15	0.39	0.68	9.96	72.40	5.90	2.46	1.30	0.34	0.15	0.19	0.05	0.05	0.00	0.05	0.10	5.75
BBB+	0.00	0.00	0.12	0.36	0.36	1.07	8.48	72.30	6.94	2.08	0.47	0.18	0.06	0.12	0.18	0.06	0.18	0.30	6.76
BBB	0.00	0.06	0.19	0.12	0.25	0.37	1.75	9.30	71.97	4.87	1.87	0.81	0.56	0.31	0.12	0.06	0.00	0.44	6.93
BBB-	0.00	0.08	0.00	0.08	0.08	0.47	0.23	1.40	10.30	69.11	4.06	2.11	0.86	0.86	0.08	0.23	0.00	0.62	9.44
BB+	0.00	0.00	0.00	0.29	0.14	0.14	0.00	0.72	2.43	13.02	62.37	5.15	1.72	0.86	0.72	0.14	1.00	1.14	10.16
BB	0.00	0.00	0.00	0.15	0.00	0.15	0.00	0.44	0.73	2.33	11.05	64.10	4.07	1.45	1.31	0.44	1.31	0.73	11.77
BB-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.54	2.95	8.32	62.28	5.10	4.03	1.61	0.67	1.34	12.75
B+	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.49	0.98	2.45	12.89	61.17	3.92	3.26	0.98	2.12	11.75
B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.21	0.42	0.63	2.72	14.23	54.39	4.18	4.18	4.81	14.02
B-	0.00	0.00	0.00	0.00	0.00	0.29	0.00	0.00	0.29	0.00	0.29	0.29	0.86	2.30	16.95	59.77	4.89	4.31	9.77
CCC/C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.42	0.84	2.10	1.68	13.45	44.96	15.55	20.59

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 62

Three-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Nonfinancials (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	65.74	7.25	8.75	2.64	1.96	0.68	0.91	0.30	0.00	0.00	0.00	0.00	0.15	0.00	0.08	0.00	0.00	0.00	11.55
AA+	6.83	49.79	16.22	8.82	2.70	2.70	1.85	0.57	0.71	0.71	0.00	0.00	0.00	0.00	0.28	0.14	0.00	0.00	8.68
AA	0.95	2.62	55.68	13.44	6.26	3.79	1.68	1.68	0.51	0.18	0.44	0.15	0.18	0.07	0.04	0.07	0.04	0.00	12.24
AA-	0.00	0.25	7.78	47.26	17.30	8.03	3.19	1.49	1.02	0.38	0.42	0.09	0.09	0.21	0.25	0.04	0.00	0.09	12.11
A+	0.00	0.13	1.45	6.08	47.48	18.19	7.15	3.19	2.01	0.51	0.35	0.29	0.16	0.38	0.32	0.05	0.05	0.24	11.95
A	0.13	0.13	0.83	1.30	8.31	50.06	12.26	6.50	3.92	1.54	0.70	0.81	0.27	0.51	0.14	0.06	0.08	0.08	12.37
A-	0.10	0.00	0.18	0.28	1.46	10.93	46.02	15.13	6.49	2.38	0.58	0.90	0.44	0.54	0.12	0.04	0.16	0.14	14.11
BBB+	0.00	0.04	0.18	0.11	0.42	2.83	11.38	42.72	17.28	4.94	1.74	1.23	0.64	0.86	0.57	0.20	0.16	0.68	14.03
BBB	0.03	0.00	0.09	0.06	0.42	1.04	3.51	11.54	44.65	10.66	3.51	2.49	1.19	1.07	0.75	0.29	0.21	0.69	17.80
BBB-	0.08	0.00	0.00	0.19	0.17	0.58	1.59	3.87	14.57	39.05	7.80	4.68	2.67	1.99	0.89	0.64	0.68	1.70	18.85
BB+	0.03	0.00	0.00	0.00	0.07	0.20	0.73	2.03	4.85	17.75	26.89	9.60	5.85	3.29	1.96	0.76	0.93	2.49	22.57
BB	0.02	0.00	0.07	0.02	0.00	0.26	0.38	0.86	2.28	6.49	9.94	28.11	11.37	6.11	2.52	1.07	1.31	4.68	24.49
BB-	0.00	0.00	0.00	0.02	0.07	0.02	0.19	0.38	1.22	1.96	3.92	10.74	28.27	10.70	5.95	2.46	1.58	6.68	25.83
B+	0.00	0.04	0.00	0.04	0.00	0.07	0.15	0.17	0.22	0.56	1.18	3.41	9.28	28.04	9.89	4.26	3.31	11.45	27.93
B	0.02	0.00	0.02	0.00	0.04	0.25	0.17	0.15	0.19	0.38	0.74	1.42	4.54	9.86	22.36	7.06	5.90	18.80	28.09
B-	0.00	0.00	0.00	0.00	0.05	0.05	0.18	0.18	0.45	0.23	0.18	1.17	1.98	5.82	8.16	16.23	7.35	25.20	32.78
CCC/C	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.24	0.36	0.30	0.06	0.60	1.07	2.68	5.48	6.37	11.44	45.68	25.49

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 63

Three-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Insurance (%)

show

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	67.64	13.53	7.10	3.59	1.27	0.52	0.07	0.00	0.00	0.00	0.07	0.07	0.00	0.00	0.15	0.00	0.30	0.37	5.31
AA+	3.80	42.21	23.37	11.96	5.07	2.17	1.09	0.18	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	9.06

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue E2
Schedule 14.4
Attachment

AA	1.87	2.01	50.90	18.05	6.71	3.04	2.70	0.83	0.90	0.55	0.00	0.21	0.07	0.35	0.07	0.07	0.21	0.35	11.13
AA-	0.49	0.74	10.59	44.83	20.20	5.83	2.05	2.22	0.49	0.08	0.25	0.08	0.00	0.25	0.00	0.00	0.00	0.49	11.41
A+	0.07	0.71	2.07	11.69	45.97	14.54	6.49	2.35	0.93	0.43	0.21	0.21	0.07	0.21	0.00	0.00	0.00	0.29	13.76
A	0.21	0.57	0.78	2.84	12.51	48.33	12.94	2.35	2.49	0.57	0.50	0.57	0.14	0.00	0.21	0.00	0.43	1.56	13.01
A-	0.00	0.17	0.78	1.74	3.31	15.17	49.00	8.37	2.96	1.48	0.78	0.26	0.70	0.09	0.09	0.17	0.26	0.96	13.69
BBB+	0.00	0.00	0.30	0.15	2.67	4.15	21.66	34.12	11.28	4.30	1.48	0.30	0.30	0.15	0.15	0.15	0.45	0.74	17.66
BBB	0.00	0.00	0.62	0.15	2.63	1.85	4.17	17.77	38.18	6.18	2.63	0.93	1.08	0.77	0.15	0.15	0.31	1.85	20.56
BBB-	0.00	0.00	0.97	0.00	0.48	0.73	2.18	5.81	16.95	40.92	5.57	1.94	0.97	0.73	0.48	0.48	1.94	2.66	17.19
BB+	0.00	0.00	0.00	0.00	0.44	2.64	1.32	1.76	4.85	14.98	28.63	3.96	4.85	2.64	0.00	0.00	3.08	4.41	26.43
BB	0.00	0.00	0.60	0.00	0.00	0.60	0.60	2.98	2.38	13.69	8.33	23.21	4.76	1.79	1.79	0.00	0.60	3.57	35.12
BB-	0.00	0.00	0.00	0.00	0.00	1.14	0.00	1.14	1.14	6.82	21.59	17.05	11.36	6.82	2.27	2.27	4.55	5.68	18.18
B+	0.00	0.00	0.00	0.00	0.00	0.00	2.56	1.71	3.42	4.27	8.55	6.84	8.55	26.50	7.69	2.56	1.71	11.97	13.68
B	0.00	0.00	0.00	0.00	0.00	1.05	2.11	1.05	0.00	1.05	1.05	5.26	8.42	13.68	30.53	2.11	1.05	3.16	29.47
B-	0.00	0.00	0.00	0.00	2.50	0.00	0.00	0.00	0.00	0.00	2.50	0.00	2.50	10.00	12.50	20.00	5.00	17.50	27.50
CCC/C	0.00	0.00	0.00	0.00	0.00	0.00	1.82	0.00	0.00	1.82	1.82	0.00	5.45	5.45	1.82	3.64	18.18	36.36	23.64

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 64

Three-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Financial Institutions (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	67.17	9.90	4.20	1.51	0.54	0.86	0.22	0.43	0.32	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.00	14.53
AA+	5.04	41.31	23.68	8.06	5.29	4.28	2.27	1.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.07
AA	1.00	1.92	46.21	18.43	12.09	5.25	1.17	0.92	0.08	0.33	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	12.51
AA-	0.00	0.34	9.94	49.41	15.47	8.30	2.54	1.36	0.62	0.11	0.06	0.00	0.06	0.00	0.06	0.06	0.00	0.23	11.46
A+	0.00	0.10	1.74	12.52	48.44	12.37	5.42	1.74	1.33	0.46	0.31	0.20	0.05	0.05	0.15	0.00	0.05	0.31	14.77
A	0.00	0.00	0.38	2.21	13.41	45.99	11.11	4.22	2.17	1.17	0.58	0.46	0.25	0.17	0.04	0.08	0.08	0.29	17.38
A-	0.11	0.11	0.33	0.93	3.77	17.59	41.62	9.83	4.92	1.80	0.60	0.55	0.38	0.33	0.38	0.05	0.22	0.71	15.78
BBB+	0.00	0.07	0.27	0.74	1.01	4.18	16.12	39.51	10.72	3.78	0.94	0.61	0.40	0.13	0.13	0.20	0.34	1.15	19.69
BBB	0.00	0.22	0.44	0.59	0.74	2.51	4.22	16.42	40.68	5.70	2.37	1.48	0.59	0.59	0.52	0.30	0.15	1.48	21.01
BBB-	0.00	0.18	0.00	0.18	0.46	1.66	1.29	5.43	14.73	36.74	5.06	1.75	1.29	1.57	0.37	0.37	0.46	3.50	24.95
BB+	0.00	0.00	0.00	0.17	0.33	0.50	0.83	3.49	6.48	17.77	28.74	5.32	1.33	1.66	2.16	0.66	0.83	3.16	26.58
BB	0.00	0.00	0.00	0.17	0.00	0.17	0.34	1.35	4.06	8.63	12.01	28.60	3.72	3.38	1.52	0.34	0.85	4.57	30.29
BB-	0.00	0.00	0.00	0.32	0.00	0.16	0.00	0.32	1.29	1.61	4.68	12.74	26.45	6.77	4.52	1.45	1.61	5.48	32.58
B+	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.39	2.12	3.85	4.62	15.61	25.05	5.78	3.28	2.70	7.90	28.52
B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.78	1.04	2.33	2.07	12.18	10.62	15.54	6.22	2.59	11.40	35.23
B-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.00	1.14	1.14	4.17	10.23	21.21	26.52	3.03	10.23	21.97
CCC/C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.49	0.49	0.49	0.49	2.96	4.43	14.29	11.33	19.70	45.32

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 65

10-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Nonfinancials (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	29.65	5.14	12.38	8.34	4.47	4.04	1.52	1.01	3.03	0.25	0.08	0.17	0.00	0.00	0.00	0.00	0.00	0.25	29.65
AA+	7.38	10.40	9.40	9.23	6.21	11.58	6.54	2.68	1.85	0.34	1.85	1.01	0.34	0.00	0.00	0.00	0.00	0.67	30.54
AA	0.92	2.09	16.15	11.63	9.04	9.12	5.69	3.05	3.14	1.76	0.50	0.54	0.08	0.21	0.00	0.04	0.04	0.33	35.65
AA-	0.16	0.64	5.20	11.25	13.00	15.39	8.92	6.53	3.45	2.34	0.69	0.69	0.53	0.85	0.11	0.16	0.00	0.42	29.67
A+	0.35	0.38	1.81	5.25	13.52	16.40	10.95	7.61	5.39	3.34	1.39	0.90	0.69	0.76	0.59	0.10	0.00	1.77	28.80
A	0.00	0.21	0.89	2.27	6.37	17.56	9.66	7.71	8.83	5.38	1.21	1.52	0.76	0.89	0.40	0.17	0.17	1.52	34.48
A-	0.20	0.00	0.33	0.63	2.80	8.68	14.74	11.78	11.91	5.26	1.68	2.14	1.15	1.09	0.39	0.10	0.07	1.81	35.26
BBB+	0.00	0.00	0.37	0.31	1.77	3.72	8.22	15.49	14.74	6.55	2.70	2.55	1.86	1.40	0.74	0.37	0.12	4.00	35.07
BBB	0.05	0.05	0.24	0.13	0.84	2.90	5.47	8.24	13.68	8.89	2.75	2.64	1.99	1.80	0.68	0.63	0.18	4.97	43.88
BBB-	0.07	0.00	0.04	0.36	0.85	1.92	2.53	6.19	9.85	9.89	4.38	3.84	3.27	2.13	1.85	0.96	0.50	8.68	42.69
BB+	0.12	0.00	0.00	0.12	0.30	0.72	1.49	3.23	8.49	7.59	4.48	4.90	4.30	3.65	2.69	1.20	0.78	12.01	43.93
BB	0.00	0.00	0.00	0.04	0.29	0.66	0.62	2.18	4.11	4.32	3.00	6.09	6.54	4.44	1.73	1.69	0.90	17.23	46.18
BB-	0.00	0.00	0.00	0.03	0.00	0.33	0.60	0.75	1.83	3.15	2.85	3.60	6.06	4.32	2.82	1.23	0.66	24.49	47.27
B+	0.00	0.04	0.00	0.00	0.00	0.24	0.16	0.65	0.59	1.26	1.02	2.36	3.41	4.32	2.84	1.58	1.02	30.42	50.09
B	0.00	0.00	0.00	0.00	0.22	0.35	0.26	0.22	0.78	0.87	1.18	1.66	2.05	1.66	2.66	1.31	0.87	37.43	48.50
B-	0.00	0.00	0.00	0.00	0.00	0.00	0.29	0.00	0.00	0.76	0.48	1.24	2.10	1.53	2.68	0.96	0.48	45.89	43.59
CCC/C	0.00	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.44	0.44	0.67	1.11	1.33	1.33	0.67	0.44	0.33	58.27	34.74

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 66

10-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Insurance (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	28.48	12.73	14.29	9.43	7.23	2.01	2.20	1.19	1.10	0.18	0.09	0.00	0.09	0.00	0.18	0.00	0.09	1.56	19.14
AA+	4.35	6.42	18.43	18.22	9.94	4.14	4.76	2.48	0.62	0.00	0.00	0.00	0.00	1.04	0.00	0.00	0.00	0.41	29.19

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AA	2.33	2.96	15.86	16.28	11.31	8.35	5.07	3.07	0.63	0.74	0.21	0.11	0.21	0.53	0.00	0.21	0.21	1.37	30.55
AA-	0.68	0.95	7.47	13.45	16.03	9.92	9.92	4.76	1.22	0.82	0.00	0.95	0.00	0.00	0.00	0.00	0.00	2.72	31.11
A+	0.40	0.27	5.39	7.55	16.17	12.13	11.19	3.23	1.21	1.35	0.54	0.27	0.54	0.00	0.00	0.00	1.08	1.89	36.79
A	0.93	0.31	2.02	5.30	10.59	15.58	10.90	2.96	3.43	0.78	2.02	0.00	0.62	0.16	0.00	0.00	0.31	6.23	37.85
A-	0.00	0.23	0.00	2.50	3.18	7.05	17.73	5.68	5.23	5.23	3.64	0.00	0.68	0.00	0.68	0.23	0.45	4.09	43.41
BBB+	0.00	0.00	0.45	4.55	6.82	3.64	6.36	7.27	10.91	8.64	1.82	1.36	0.00	0.00	0.00	0.00	0.91	8.18	39.09
BBB	0.00	0.00	3.67	4.00	3.00	1.67	6.00	9.00	12.00	3.67	1.67	1.33	0.00	0.33	0.00	0.00	0.33	8.33	45.00
BBB-	0.00	0.00	0.00	0.00	0.75	0.75	0.75	5.97	11.94	26.87	2.24	2.24	0.75	0.00	0.75	0.75	0.75	10.45	35.07
BB+	0.00	0.00	0.00	2.08	1.04	9.38	6.25	2.08	2.08	2.08	9.38	3.13	3.13	1.04	0.00	3.13	0.00	36.46	18.75
BB	0.00	0.00	0.00	1.25	1.25	1.25	2.50	0.00	12.50	5.00	1.25	1.25	1.25	2.50	0.00	0.00	0.00	17.50	52.50
BB-	0.00	0.00	0.00	0.00	0.00	2.33	0.00	6.98	13.95	2.33	0.00	0.00	2.33	6.98	0.00	0.00	0.00	32.56	32.56
B+	0.00	0.00	0.00	0.00	3.39	1.69	3.39	3.39	6.78	15.25	8.47	0.00	1.69	5.08	0.00	0.00	1.69	28.81	20.34
B	0.00	0.00	0.00	0.00	0.00	3.03	12.12	6.06	9.09	6.06	9.09	9.09	0.00	0.00	0.00	0.00	3.03	9.09	33.33
B-	0.00	0.00	0.00	0.00	7.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.43	71.43
CCC/C	0.00	0.00	0.00	0.00	4.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.83	25.00

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Table 67

10-Year Average Global Corporate Transition Matrix By Rating Modifier (1981-2011): Financial Institutions (%)

Rating	AAA	AA+	AA	AA-	A+	A	A-	BBB+	BBB	BBB-	BB+	BB	BB-	B+	B	B-	CCC/C	D	NR
AAA	26.56	9.23	6.68	2.84	3.69	3.13	1.99	1.85	0.57	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.90
AA+	1.49	6.69	8.92	14.13	11.90	14.13	9.29	3.72	1.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.88
AA	0.73	0.73	16.00	17.46	12.33	6.47	3.79	2.69	1.22	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.73	37.24
AA-	0.47	0.66	9.02	21.62	17.86	11.00	4.42	2.44	1.60	0.66	0.09	0.00	0.00	0.00	0.09	0.00	0.00	0.94	29.14
A+	0.00	0.35	4.15	10.64	18.51	12.80	5.10	3.63	2.85	1.30	0.87	0.09	0.26	0.00	0.17	0.00	0.00	1.04	38.24
A	0.00	0.00	1.24	6.54	12.10	19.36	7.00	2.81	1.64	1.05	0.20	0.00	0.72	0.20	0.07	0.00	0.00	0.98	46.11
A-	0.00	0.00	0.89	2.68	6.94	11.89	12.69	6.54	3.27	1.88	2.58	0.50	0.20	0.30	0.00	0.00	0.00	2.97	46.68
BBB+	0.00	0.15	0.29	4.25	3.96	5.72	8.36	6.60	5.57	2.20	1.17	0.73	0.44	0.15	0.29	0.15	0.44	3.52	56.01
BBB	0.00	0.58	0.58	2.33	1.89	1.02	8.58	9.74	8.58	4.36	1.60	0.44	0.15	0.15	0.00	0.00	0.29	3.20	56.54
BBB-	0.00	0.00	0.00	0.54	2.17	3.62	2.90	9.24	8.88	6.16	2.36	0.54	0.54	1.45	1.09	0.18	0.54	9.42	50.36
BB+	0.00	0.00	0.00	0.00	0.96	6.07	0.96	4.79	6.71	4.79	2.24	0.32	0.32	0.64	0.64	0.64	0.00	5.43	65.50
BB	0.00	0.00	0.00	0.00	0.74	2.96	1.11	5.93	6.30	7.41	0.74	1.85	2.22	0.37	1.48	0.00	0.37	11.85	56.67
BB-	0.00	0.00	0.00	0.00	0.00	0.00	0.75	3.01	0.75	1.88	2.63	2.26	0.00	1.13	2.26	3.38	0.38	18.42	63.16
B+	0.00	0.00	0.00	0.00	0.00	0.00	1.73	4.33	2.60	2.16	1.73	3.90	4.76	3.46	2.60	2.16	0.00	14.72	55.84
B	0.00	0.00	0.00	0.00	0.00	1.83	0.00	1.22	0.00	3.05	2.44	1.22	1.22	2.44	3.05	1.22	0.00	26.22	56.10
B-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.75	5.00	10.00	1.25	3.75	0.00	0.00	31.25	45.00
CCC/C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.20	4.40	3.30	2.20	2.20	0.00	37.36	48.35

Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Appendix III: Gini Methodology

To measure ratings performance or ratings accuracy, we plotted the cumulative share of issuers by rating against the cumulative share of defaulters in a Lorenz curve to visually render the accuracy of their rank ordering. Max O. Lorenz developed the Lorenz curve as a graphical representation of the proportionality of a distribution. To build the Lorenz curve, the observations are ordered from the low end of the ratings scale ('CCC'/'C') to the high end ('AAA'). If Standard & Poor's corporate ratings only randomly approximated default risk, the Lorenz curve would fall along the diagonal. Its Gini coefficient--which is a summary statistic of the Lorenz curve--would thus be zero. If corporate ratings were perfectly rank-ordered so that all defaults occurred only among the lowest-rated entities, the curve would capture all of the area above the diagonal on the graph and its Gini coefficient would be one (see chart 31). The procedure for calculating the Gini coefficients is illustrated below--divide area B by the total area A plus B. In other words, the Gini coefficient captures the extent to which actual ratings accuracy diverges from the random scenario and aspires to the ideal scenario.

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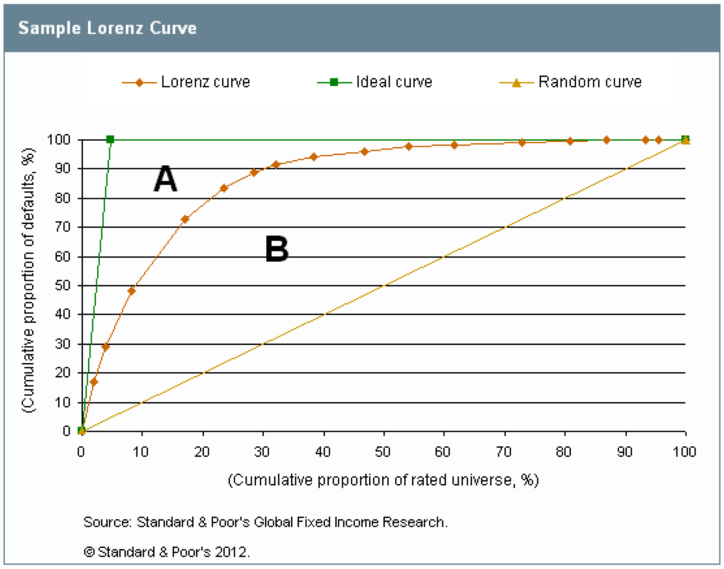
Chart 31



Related Research

- **2011 Default Synopses**, March 21, 2012
- **The U.S. Corporate Default Rate Is Forecasted To Rise To 3.3% In 2012**, Feb. 2, 2012
- **Recovery Study (U.S.): Piecing Together The Performance Of Defaulted Instruments After The Recent Credit Cycle**, Dec. 1, 2011

And watch the related CreditMatters TV segment titled, "Standard & Poor's 2011 Annual Global Corporate Default Study And Rating Transitions," dated March 21, 2012.)

Global Fixed Income Research: Diane Vazza, Managing Director, New York (1) 212-438-2760; **diane_vazza@standardandpoors.com**
Nicholas Kraemer, Director, New York (1) 212-438-1698; **nick_kraemer@standardandpoors.com**

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SEC INTERROGATORY #5

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/2/1

Please provide any drafts of the Concentric Report which show markups or editorial changes proposed by Enbridge personnel. Please provide a detailed description of the involvement of Enbridge personnel in the drafting of the report.

RESPONSE

EGD is not prepared to produce drafts of the Concentric Report. The final version of the Concentric Report, which is filed at Exhibit E2, Tab 2, Schedule 1, sets out Concentric's expert opinion, and it is that opinion which is relied upon by EGD in this proceeding. As there is no ambiguity in the Concentric Report which would be explained by production of previous drafts, there is no need for the requested production.

Witnesses: J. Coyne
R. Fischer
J. Lieberman
M. Lister

SEC INTERROGATORY #6

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: [E2/2/1, p. 18]

Provide Concentric's evidence for the statement "large portions of these natural gas transmission and distribution systems are reaching the end of their design lives". Please confirm that this statement is intended to be indicative of the Applicant's system. Please describe how the assumption that this statement is true influenced the expert's conclusions.

RESPONSE

Concentric refers to Figure 2 as evidence that large portions of natural gas transmission and distribution systems are reaching the end of their design lives. The statement applied generically to Canadian gas infrastructure investment as reflected in the Figure, and was not specifically addressing EGD's distribution system. According to Figure 2, capital investment in the Canadian natural gas sector was steadily building between the years 1960 and 1981, with substantial investment increases in 1974 and 1975. This indicates that the bulk of the Canadian gas distribution system is between 30 and 50 years old, with significant investment approaching 40 years old. According to EGD's Depreciation Study filed in this Application, the average service lives of gas distribution services, mains and meters range from 35 to 50 years.[1]

[1] EGD Depreciation Study, EB-2011-0354, Part II-25, Survivor Curve Judgments.

Witnesses: J. Coyne
J. Lieberman
Concentric

SEC INTERROGATORY #7

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/2/1, p. 18

Please provide all rating reports for the Applicant after April 25, 2011.

RESPONSE

The following rating reports are attached:

- Attachment 1 - S&P – December 15, 2011
- Attachment 2 - DBRS – April 25, 2011
- Attachment 3 - DBRS – April 4, 2012
- Attachment 4 - DBRS – June 28, 2012

Witnesses: R. Fischer
M. Lister
D. Yaworsky

STANDARD & POOR'S

Global Credit Portal®
RatingsDirect®

December 15, 2011

Enbridge Gas Distribution Inc.

Primary Credit Analyst:
Gavin MacFarlane, Toronto (1) 416-507-2545; gavin_macfarlane@standardandpoors.com

Secondary Contact:
Nicole Martin, Toronto (1) 416-507-2560; nicole_martin@standardandpoors.com

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Enbridge Gas Distribution Inc.

Major Rating Factors

Strengths:
- Low-risk regulated cash flows
- Monopoly gas network business
- No commodity risk

Weaknesses:
- Exposure to weather-induced variability in gas demand and cash flows

Corporate Credit Rating

A-/Stable/--

Rationale

The ratings on Toronto-based Enbridge Gas Distribution Inc. (Enbridge Gas or EGD) reflect Standard & Poor's Ratings Services' view of the utility's monopoly position, consistent profitability, and lack of exposure to commodity risk. We believe cash-flow variability due to weather offsets the strengths modestly.

In our view, supporting Enbridge Gas' excellent business risk profile is one of the most attractive gas utility franchises in Canada, which itself is characterized by favorable growth prospects, a high population density, and a fair regulatory system. The company's Ontario-based service franchise covers the Toronto region, as well as the Niagara Peninsula and the Ottawa-Peterborough area. In addition, EGD owns gas storage capacity representing about 24% of its annual gas deliveries. The company had C$2.8 billion in debt (Standard & Poor's-adjusted) at Sept. 30, 2011.

We believe that Enbridge Gas' natural monopoly and stable growth in its customer base provide cash flow stability. Furthermore, cash flow security stems from the company's regulated rates determined under an incentive formula. Incentive regulation (IR) could allow EGD to benefit from productivity enhancements and incremental revenues and has not led to material variability in cash flows. The company expects to operate under IR in 2012, cost-of-service in 2013, and IR in 2014. Enbridge Gas does not face any commodity price risk, because it passes the cost of gas to customers through an established quarterly adjustment mechanism.

In our view, offsetting the company's excellent business risk profile somewhat is its exposure to weather-induced variability in gas demand and related cash flows. Under the current regulatory framework, revenue shortfalls can result from lower-than-forecast volumes (typically from a warmer-than-expected winter). This shortfall cannot be recovered and can lead to somewhat greater volatility in earnings compared with those of other regulated utilities in Canada.

We expect EGD's adjusted funds from operations (AFFO)-to-total debt and AFFO interest coverage ratios will likely remain near 15%-20% and about 3.0x, respectively. Adjusted total debt-to-total capital was about 62% as of Dec. 30, 2010, slightly higher than that of 2009.

The corporate credit rating on Enbridge Gas is equivalent to our stand-alone evaluation of the company; at the current level, the ratings on ultimate parent, Enbridge Inc. (A-/Stable/--) do not constrain the ratings on EGD. However, a material intercorporate lending arrangement between the parent and subsidiary links the credit profiles of the two. Accordingly, any decline in the rating on the parent would likely result in a similar decline in the rating on Enbridge Gas.

Liquidity

We believe EGD has adequate liquidity as per our criteria. Our assessment incorporates the following expectations and assumptions:

- We expect the company's sources over uses to exceed 1.2x during the next six months, even in the unlikely event that EBITDA declines by 15%.
- Enbridge Gas will continue to have solid relationships with its banks, a generally high standing in credit markets, and very prudent risk management.
- We expect sources of liquidity in the next six months to include FFO of more than C$250 million, and as of Sept. 30, 2011, revolver availability of C$275 million and negligible cash on hand.
- Uses of funds are forecast to include capital spending of about C$200 million and dividends of about C$75 million.
- We also expect parental support if required, provided the parent was economically incentivized to do so.

As of Sept. 30, Enbridge Gas complied with all of its covenants.

Accounting

Enbridge Gas reports in Canadian dollars and uses Canadian generally accepted accounting principles (GAAP) but plans to convert to U.S. GAAP for interim and annual financial statement reporting Jan. 1, 2012. We do not expect this to have a rating impact.

To better reflect the financial risk EGD has assumed, Standard & Poor's makes an offsetting adjustment to its total debt outstanding for the amounts relating to purchased gas-in-storage. The company's commercial paper program finances gas-in-storage amounts, and, as such, reports it as part of short-term debt. Given our expectation of full commodity cost recovery under the Ontario Energy Board's provisions and to eliminate the seasonality, we remove the amounts from short-term debt and total assets. Enbridge Gas had total reported consolidated debt of C$3.14 billion (including C$375 million in loans from an affiliate company) in 2010; however, following our adjustments, the total debt that we used for our analysis and ratio calculations was C$2.88 billion.

Outlook

The stable outlook reflects our expectations of EGD's continued sound operations and a fair regulatory environment. Given the intercorporate transaction links in the ratings to the parent, a positive outlook or upgrade is unlikely unless Enbridge's credit profile also improves. A negative outlook or downgrade could occur if we were to lower the rating on the parent.

Table 1

Enbridge Gas Distribution Inc.--Peer Comparison

Industry Sector: Gas

	--Fiscal year ended Dec. 31, 2010--			--Fiscal year ended Sept. 30, 2011--
(Mil. C$)	**Enbridge Gas Distribution Inc.**	**Union Gas Ltd.**	**Terasen Gas Inc.**	**Gaz Metro Inc.**
Rating as of Dec. 15, 2011	A-/Negative/--	BBB+/Stable/A-2	NR	A-/Stable/--
Revenues	2,475.0	1,830.0	1,362.1	1,962.8
EBITDA	662.0	639.4	326.8	433.1
Net income from continuing operations	193.0	206.0	93.2	43.7
Funds from operations (FFO)	470.1	443.0	183.5	405.7
Capital expenditures	362.0	232.7	135.6	201.5
Free operating cash flow	139.1	(46.6)	33.2	195.8
Discretionary cash flow	(69.9)	(354.6)	(50.8)	110.5
Cash and short-term investments	0.0	12.0	15.2	38.4
Debt	2,877.9	2,684.1	1,705.0	1,904.6
Equity	1,756.9	1,241.4	935.2	1,195.4
Adjusted ratios				
EBITDA margin (%)	26.7	34.9	24.0	22.1
EBITDA interest coverage (x)	3.5	3.8	2.9	3.8
EBIT interest coverage (x)	2.3	2.6	2.1	2.5
Return on capital (%)	9.0	10.8	8.2	8.6
FFO/debt (%)	16.3	16.5	10.8	21.3
Free operating cash flow/debt (%)	4.8	(1.7)	1.9	10.3
Debt/EBITDA (x)	4.3	4.2	5.2	4.4
Total debt/debt plus equity (%)	62.1	68.4	64.6	61.4

NR--Not rated.

Table 2

Enbridge Gas Distribution Inc.--Financial Summary

Industry Sector: Gas

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2010**	**2009**	**2008**	**2007**	**2006**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--
Revenues	2,475.0	2,903.1	3,104.9	2,953.9	3,016.1
EBITDA	662.0	691.9	656.1	620.7	496.5
Net income from continuing operations	193.0	221.5	211.4	189.9	127.2
Funds from operations (FFO)	470.1	492.8	483.6	419.0	283.8
Capital expenditures	362.0	364.6	406.1	381.9	389.0
Dividends paid	209.0	183.1	160.7	67.7	177.1
Debt	2,877.9	2,722.0	2,962.0	2,758.6	2,741.8
Preferred stock	50.0	50.0	50.0	50.0	50.0
Equity	1,756.9	1,846.5	1,822.8	1,819.6	1,614.8

Table 2

Enbridge Gas Distribution Inc.--Financial Summary (cont.)					
Debt and equity	4,634.9	4,568.5	4,784.8	4,578.2	4,356.6
Adjusted ratios					
EBITDA margin (%)	26.7	23.8	21.1	21.0	16.5
EBIT interest coverage (x)	2.3	2.4	2.3	2.1	1.7
FFO interest coverage (x)	3.4	3.5	3.3	2.9	2.3
FFO/debt (%)	16.3	18.1	16.3	15.2	10.4
Discretionary cash flow/debt (%)	(2.4)	15.2	(6.9)	3.7	(3.7)
Net cash flow/capex (%)	72.1	85.0	79.5	92.0	27.4
Debt/debt and equity (%)	62.1	59.6	61.9	60.3	62.9
Return on capital (%)	9.0	10.0	10.0	10.1	8.2
Return on common equity (%)	10.2	11.5	11.1	10.7	7.3
Common dividend payout ratio (unadjusted; %)	112.6	86.2	76.6	50.4	119.3

Table 3

Reconciliation Of Enbridge Gas Distribution Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2010--									
Enbridge Gas Distribution Inc. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	3,142.0	1,927.0	2,475.0	666.0	396.0	186.0	503.0	503.0	210.0	365.0
Standard & Poor's adjustments										
Intermediate hybrids reported as equity	50.0	(50.0)	N/A	N/A	N/A	1.0	(1.0)	(1.0)	(1.0)	N/A
Postretirement benefit obligations	17.9	(120.1)	N/A	(10.0)	(10.0)	N/A	2.1	2.1	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	3.0	(3.0)	(3.0)	N/A	(3.0)
Share-based compensation expense	N/A	N/A	N/A	6.0	N/A	N/A	N/A	N/A	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	44.0	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(31.0)	N/A	N/A
Debt--Other	(332.0)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	(264.1)	(170.1)	0.0	(4.0)	34.0	4.0	(1.9)	(32.9)	(1.0)	(3.0)

Table 3

Reconciliation Of Enbridge Gas Distribution Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)

Standard & Poor's adjusted amounts	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	2,877.9	1,756.9	2,475.0	662.0	430.0	190.0	501.1	470.1	209.0	362.0

N/A--Not applicable.

Related Criteria And Research

- Rating Criteria For U.S. Midstream Energy Companies, Dec. 18, 2008
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008

Ratings Detail (As Of December 15, 2011)	
Enbridge Gas Distribution Inc.	
Corporate Credit Rating	A-/Stable/--
Commercial Paper	
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preference Stock (1 Issue)	BBB
Canadian Preferred Stock Rating (1 Issue)	P-2
Senior Unsecured (16 Issues)	A-
Corporate Credit Ratings History	
06-Dec-2011	A-/Stable/--
23-Mar-2011	A-/Negative/--
25-Nov-2003	A-/Stable/--
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Enbridge Inc.	
Issuer Credit Rating	A-/Stable/--
Commercial Paper	
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preferred Stock (3 Issues)	BBB
Canadian Preferred Stock Rating (3 Issues)	P-2
Senior Unsecured (18 Issues)	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Rating Report
Report Date:
April 4, 2012
Previous Report
April 25, 2011

DBRS
Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,500 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly-owned subsidiary of Enbridge Inc. (rated A (low)).

CP Limit: $700 million

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Ratings Update

DBRS has confirmed the Unsecured Debentures & Medium-Term Notes, Commercial Paper, and Cumulative & Cumulative Redeemable Convertible Preferred Share ratings of Enbridge Gas Distribution Inc. (EGD or the Company) at “A”, R-1 (low) and Pfd-2 (low), respectively, all with Stable trends. The rating confirmation is based on EGD’s low business risk operations, stable regulatory environment in Ontario, strong franchise area and stable financial profile.

EGD’s low business risk profile is supported by a large customer base (approximately two million customers, the largest in Canada), which has allowed the Company to achieve operational efficiency and generate earnings in excess of approved return on equity (ROE) under the incentive regulation (IR) framework since 2008. The Company benefits from a stable regulatory system, having no exposure to gas price risk in Ontario, where it generates approximately 98% of its revenues. EGD’s franchise area (largely in the Greater Toronto Area) is viewed as one of the most rapidly growing and economically strong service areas in Canada. Approximately 95% of the Company’s earnings are contributed by relatively stable regulated distributions, transportation and storage, with the remainder contributed by unregulated storage business, which benefits from strong demand, due to its strategic locations.

EGD’s financial profile remained stable in 2011, with all credit metrics being commensurate with DBRS’s “A” rating guidelines. DBRS notes that the Company requires significant liquidity to finance working capital (mostly gas inventory for winter distributions). Given the low gas price environment, EGD’s liquidity remains adequate to meet its operational needs. Over the medium term, moderate cash flow deficits are expected, due to a large capex program. However, EGD’s current debt leverage is well below the regulatory capital structure of 36% equity, providing EGD with significant financial flexibility. DBRS expects the Company to remain prudent in funding its cash shortfalls and maintaining its credit metrics within the “A” rating category. In August 2011, the Company financed its $66 million acquisition of 15-megawatt (MW) solar power assets from its parent, Enbridge Inc., with equity, which was viewed as positive to the financial profile.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics

Challenges
(1) Weather-related volume risk
(2) Low ROE and limited rate base growth
(3) Cash flow deficits

Financial Information

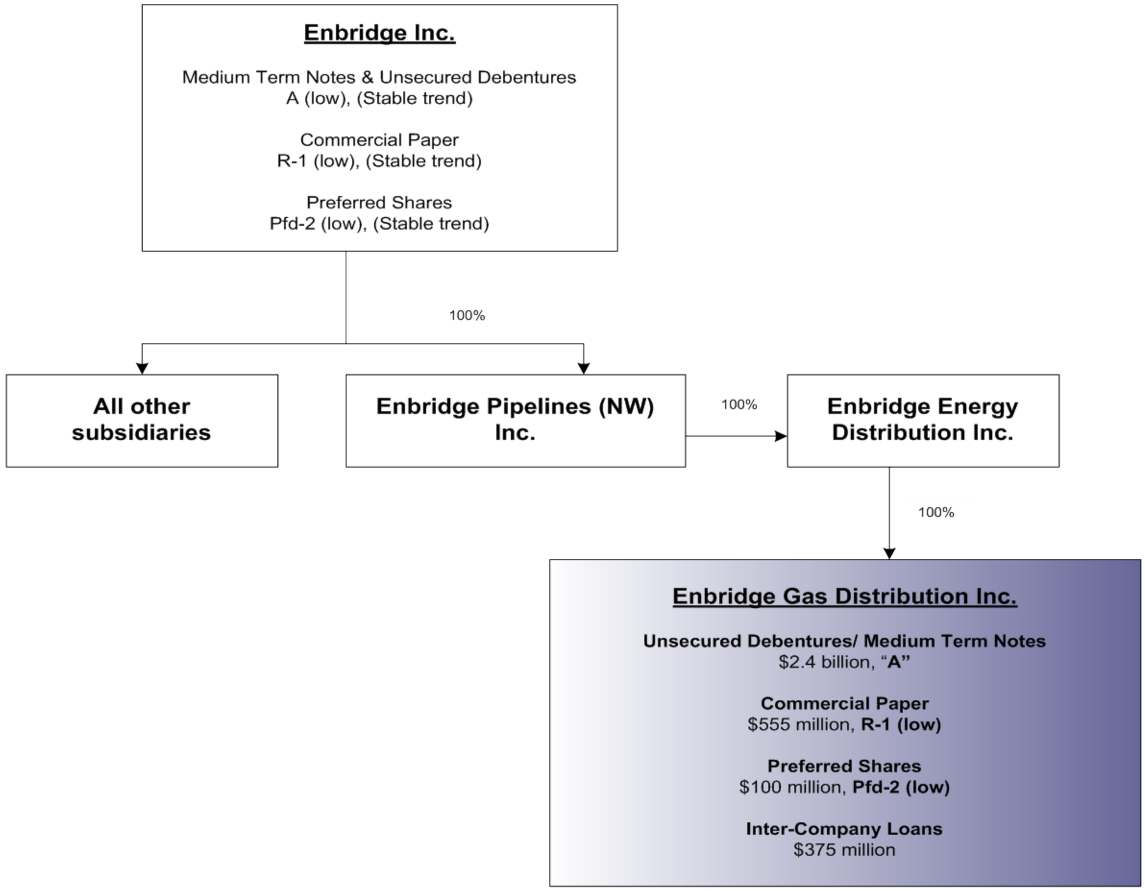
Enbridge Gas Distribution Inc.	For the year ended December 31				
($ millions)	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. Items	211	193	221	211	190
Cash flow from operations	497	467	504	483	423
Total debt in capital structure (1)	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT gross interest coverage (times) (1)	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/EBITDA (times) (1)	3.85	3.59	3.32	4.12	3.90
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company prefered dividend income and interest expense.

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Simplified Organizational Chart



Enbridge Gas Distribution Inc.

Report Date:
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Rating Considerations Details

Strengths

(1) Low business risk, stable regulatory framework. EGD's low risk business is viewed as low, underpinned by its gas distribution operations and a stable regulatory environment. Gas supply costs are adjusted quarterly and are passed through to customers. Currently, the Company operates under a long-term incentive regulation (IR) framework until 2013, which provides incentives for improved efficiency and long-term regulatory stability.

(2) Strong franchise, large customer base. EGD is the largest regulated natural gas distributor in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong. The size of the customer base allows the Company to achieve operational efficiency. EGD has generated returns on approved equity levels in excess of 100 basis points of approved ROE over the past four years.

(3) Reasonable balance sheet and credit metrics. EGD maintains a reasonable balance sheet and strong credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt/36% equity. The current debt leverage (56%) provides the Company with significant financial flexibility.

Challenges

(1) Volume risk due to weather. Weather remains the most significant risk, as forecast volumes – based on the normalized weather – are built into the Company's base rates, while actual usage varies with weather. Therefore, colder weather than normal in the forecast generally results in higher earnings compared to periods of warmer than normal weather.

(2) Limited rate base growing and low ROE during the IR period. Until the next cost-of-service (COS) application expected in 2013, the rate base growth will be limited and the relatively low current approved ROE of 8.39% will not be changed.

(3) Free cash flow deficits. Free cash flow deficits almost doubled in 2011 to $198 million as a consequence of increased dividend and growing capex. Negative free cash flow is expected to continue in 2012, since Capex is expected to remain high. While incremental cash flow is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million), cash contributions from these power projects will be very modest.

Earnings and Outlook

($ millions CAD)	For the 12 months ended December 31 2011	2010	2009	2008	2007
Net gas distribution revenue	669	605	576	506	485
Gas transportation service revenue	352	390	449	505	500
Gas distribution margin	1,021	995	1,025	1,011	985
Other revenue	104	108	108	94	81
Total revenue	1,125	1,103	1,133	1,105	1,066
EBITDA	665	666	699	684	644
EBIT	384	396	445	445	416
Earnings sharing	13	19	19	6	0
Intercompany dividend income	63	63	63	63	63
Interest expense (external)	(143)	(151)	(155)	(175)	(159)
Interest expense (intercompany)	(27)	(27)	(27)	(27)	(27)
Net income before extra. Items	211	193	221	211	190
Extra items	0	0	0	0	0
Reported net income	211	193	221	211	190
Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%
Actual ROE	10.79%	9.91%	11.32%	11.06%	10.58%

Summary

- The Company's earnings are contributed mainly by gas distribution operations (59% of 2011 net revenue) and gas transportation operations (31% of net revenue), with the remaining contributed by the storage business.
- Most earnings from gas distribution operations are generated by EGD, with a small portion (about 2% of revenues) contributed by its wholly-owned St. Lawrence, a natural gas distributor in New York State.
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 5% of overall earnings (DBRS estimates).
- Earnings in regulated operations are mainly driven by rate base growth and approved ROE (both of which remained stable in 2011), as well as weather, which in 2011 was colder than 2010 and was largely responsible for a slight increase in earnings.
- In addition to colder weather, modest customer growth and higher distribution charges also contributed to the increase.
- DBRS notes that transportation revenue have declined since 2007, due to a gradual decrease in volumes.
- Earnings sharing represents EGD's 50% share of the actual return on the approved equity level (excluding the effect of weather), in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million intercompany loan outstanding at December 31, 2011. The interest expense on this loan was $27 million in 2011.

Outlook

- The Company's earnings, under normal weather conditions, should increase moderately in 2012, driven primarily by customer growth in the Company's franchise areas.
- The rate base and ROE are not expected to change until 2013, the rebasing year for EGD.
- The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Earnings growth is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million). However, the earnings contribution from these power projects will be very modest.

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Financial Profile

Consolidated Cash Flow Statement: EGD	For the year ended December 31				
($ millions CAD)	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. items	211	193	221	211	190
Depreciation & amortization	281	270	254	239	228
Deferred income taxes/Other	5	4	29	33	5
Cash flow from operations	497	467	504	483	423
Dividends paid	(220)	(210)	(185)	(163)	(70)
Capex	(475)	(365)	(370)	(411)	(385)
Free cash flow before WC	(198)	(108)	(51)	(91)	(32)
Changes in working capital (WC)	17	45	467	(115)	136
Net free cash flow	(181)	(63)	416	(207)	103
Acquisitions (*)	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	0
Net changes in equity (*)	0	0	0	0	88
Net changes in debt	174	69	(469)	261	(167)
Other	3	(13)	(15)	6	(14)
Change in cash	(4)	(7)	(68)	60	10
Total external debt ($ millions)	2,562	2,391	2,318	2,818	2,514
Inter-company debt ($ millions)	375	375	375	375	375
Total debt/Capital (1)	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT interest coverage (times) (1)	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	19.4%	19.5%	21.7%	17.1%	16.8%
Dividends/Cash flow	43.9%	44.5%	35.9%	32.7%	15.4%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.

(*) In August 2011, EGD issued $66 million to finance its $66 million solar asset acquisition from Enbridge Inc.

Summary

- Higher earnings and depreciation contributed to increased cash flow from operations. However, in 2011 free cash flow deficits almost doubled to $198 million as a result of increased dividends and large capex.
- Higher capex in 2011 was mainly due to its customer care system and unregulated storage expansion.
- EGD has a targeted dividend payment of 90% to 100%, subject to maintaining a capital structure in line with regulatory levels.
- As a result, even the Company financed cash deficits with debt, though its capital structure remained stable (compared to 2010) and was well within the regulatory capital structure of 36% equity.
- Other key credit metrics: EBIT-interest coverage and cash flow-to-debt ratio remained stable and were in line with the “A” rating category.
- The Company issued $66 million in equity to finance its $66 million acquisition of solar assets from Enbridge Inc. However, due to the nature of inter-company transaction, the issuance of equity did not record in the cash flow statement in 2011, though the equity base increased by $66 million.

Outlook

- Capex for 2012 is expected to be approximately $440 million on capital projects and maintenance. Capital projects largely include the iron cast replacement program, construction of the technical training program and power generation.
- As a result, the Company is expected to generate free cash flow deficits of approximately $160 million in 2012. DBRS expects EGD to remain prudent in its financing of the cash shortfalls in order to maintain its balance sheet leverage within “A” rating guidelines.

Long-Term Debt Maturities and Liquidity

Bank Lines/Liquidity

Credit Facilities			As at Dec. 31, 2010
	Total Facilites	**Credit Facilities Draws**	**Available**
Committed lines of credit	700	545	155
Uncommitted lines of credit*	12	10	2
Total	712	555	157

* The uncommitted lines of credit are at St. Lawrence Gas, Inc.

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capital expenditures.
- Working capital requirements are very seasonal and heavily influenced by the volatility of gas prices.
- EGD has a $700 million CP program, of which $155 million was available at the end of 2011. The CP program is fully backed by a $700 million, 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate. Nevertheless, a combination of cold weather and high gas prices could exhaust the Company's available liquidity. However, this scenario is unlikely, given the current low gas price environment.

Debt	As at Dec. 31, 2011 (CAD millions)
Commercial paper	555
Bank overdraft	7
Debentures	85
Medium-term notes	2,295
Total	**2,942**
Other and Deferred debt issue costs	(5)
Total Debt	**2,937**

Long-Term Debt Maturity schedule	Less than 1 year	1-3 years	3-5 years	ereafter	Total
As at Dec. 31, 2011 (CAD millions)	-	400	-	1,974	2,374

- Refinancing the debt is still manageable, despite $400 million of debt due in the coming three years.
- In April 2011, EGD repaid its $150 million of 10.80% debentures. The Company then issued $100 million medium term notes (MTNs) at 4.95%, as well as additional draws on its credit facilities at lower interest rates. The company took the opportunity of a low interest rate environment to refinance, lowering interest expense for future years.
- EGD is subject to an EBIT interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
- The covenant does not apply to debt issuance for refinancing.
- The Company was in compliance with the test at fiscal year-end 2011.

Inter-company debt

- As of December 31, 2011, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.

Regulation

Regulatory Overview

The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution: Ontario

- In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan, to a maximum of an additional two years.
- Revenue escalation adjusts distribution revenues every year (50% of inflation in 2011 and 45% inflation in 2012), relying on an annual process to forecast volume and customer additions.
- The Company is allowed to have several costs and deferred accounts outside of revenue escalation formulae, including capex invested in new power generation and expenses above a defined threshold.
- The Company's 2011 ROE of 8.39% and deemed equity of 36% will remain unchanged until 2013.
- EGD will retain earnings in excess of the approved ROE up to a 100-basis point and will share equally with customers the actual return on the approved equity level (excluding the effects of weather) in excess of 100 basis points above the approved ROE.
- In September 2011, EGD filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The OEB approved $1,004 million for 2012, or 98% of the requested amount. The rate adjustment was effective January 1, 2012.
- A hearing with respect to the remaining amount of $20 million (or 2%) was held by the OEB in January 2012, with a decision expected by April 2012.

Gas Distribution: New York

- The Company owns St. Lawrence Gas Company (SLG), which provides natural gas distribution services to 15,500 customers in New York State.
- The regulatory framework in New York is under cost of service and is viewed as stable. The approved ROE for 2011 was 10.5% on a deemed equity of 50%. Any earnings above 11% will be shared equally with customers. SLG had no earnings sharing in 2011 and 2010.
- Gas supply costs are adjusted annually.

Gas Storage

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB's change of EGD's pricing policy in 2007.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Enbridge Gas Distribution Inc.

Balance Sheet ($ millions CAD)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2011**	**2010**	**2009**	**Liabilities & Equity**	**2011**	**2010**	**2009**
Cash & equivalents	9	13	0	S.T. borrowings	563	349	1,036
Accounts receivable	402	457	439	Current portion L.T.D.	0	150	150
Inventories	380	400	396	Accounts payable	67	57	25
Others	261	345	362	Deferred tax	2	5	5
				Others	646	793	756
Total Current Assets	**1,052**	**1,215**	**1,197**	**Total Current Liabilities**	**1,278**	**1,354**	**1,972**
Net fixed assets	4,770	4,458	4,290	Long-term debt (L.T.D.)	2,374	2,267	1,507
Future income tax assets	0	0	0	Deferred income taxes	178	171	185
Goodwill & intangibles	179	167	179	Other L.T. liabilities	1,502	1,433	1,347
Investments & others	1,314	1,312	1,312	Shareholders equity	1,983	1,927	1,967
Total Assets	**7,315**	**7,152**	**6,978**	**Total Liab. & SE**	**7,315**	**7,152**	**6,978**

Liquidity & Capital Ratios	**2011**	**2010**	**2009**	**2008**	**2007**
Current ratio (times)	0.82	0.90	0.61	0.66	0.98
Total debt in capital structure	59.7%	58.9%	57.8%	62.2%	60.5%
Cash flow/Total debt	16.9%	16.9%	18.7%	15.1%	14.6%
Cash flow/Capex (times)	1.05	1.28	1.36	1.17	1.10
(Cash flow - Dividends)/Capex (times)	0.58	0.70	0.86	0.78	0.92
Dividend payout ratio	104.3%	108.8%	83.7%	77.2%	36.9%
Dividends/Cash flow	43.9%	44.5%	35.9%	32.7%	15.4%
Profitability Ratios					
EBITDA margin	27.0%	26.9%	24.1%	22.0%	21.8%
EBIT margin	15.6%	16.0%	15.3%	14.3%	14.1%
Profit margin	8.6%	7.8%	7.6%	6.8%	6.4%
Return on equity	10.8%	9.9%	11.3%	11.1%	10.6%
Return on capital	6.4%	6.3%	6.6%	6.5%	6.0%
Allowed ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.5%	10.5%	-	-	-
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense					
Cash flow/Debt	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/Capital	56.4%	55.4%	54.1%	59.3%	57.1%
EBITDA gross interest coverage (times)	4.65	4.41	4.51	3.92	4.06
EBIT gross interest coverage (times)	2.69	2.62	2.87	2.55	2.62
Debt/EBITDA (times)	3.85	3.59	3.32	4.12	3.90

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2011	2010	2009	2008	2007
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Notes:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
April 25, 2011

Previous Report
January 8, 2010

Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. The Company also distributes natural gas to approximately 15,000 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly-owned subsidiary of Enbridge Inc. (rated A (low)).

CP Limit: $700 million

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Ratings Update

DBRS has today confirmed the Unsecured Debentures & Medium-Term Notes, Commercial Paper, and Cumulative & Cumulative Redeemable Convertible Preferred Share ratings of Enbridge Gas Distribution Inc. (EGD or the Company) at "A", R-1 (low) and Pfd-2 (low), respectively, all with Stable trends based on EGD's low business risk operations, stable regulatory environment, strong franchise area and stable financial profile. The regulatory environment remains reasonable and stable, allowing the Company to recover its operating expenses and capital expenditures in a timely fashion. The ratings also reflect the low allowed ROE under which the Company must operate until 2012.

EGD currently benefits from productivity enhancements and incremental revenues under a 2008 Ontario Energy Board (OEB) approved incentive regulation (IR) framework (from 2008 to 2012). While a subsequent OEB general cost of capital decision provides for an initial ROE of 9.75% to be incorporated into a utility's 2010 Cost of Service Application, EGD's ROE of 8.39% will remain unchanged throughout the IR period. In May 2010, the OEB issued a decision that the new ROE could not be used to calculate earnings sharing with ratepayers. The Company's appeal of that decision was heard by the Ontario Divisional court in January 2011, with a decision pending. The ROE increase will likely be positive for EGD when the IR is renewed in 2013. (Continued on page 2.)

Rating Considerations

Strengths
(1) Low business risk operations with a stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics
(4) Price competitiveness of natural gas

Challenges
(1) Weather-related volume risk
(2) Significant seasonal liquidity requirements
(3) Moderate cash flow deficits due to increased capital expenditures
(4) Low allowed ROE

Financial Information

Enbridge Gas Distribution Inc.	For the 12 months ended				
	Dec. 10	Dec. 09	Dec. 08	Dec. 07	Dec. 06
EBIT interest coverage	2.4	2.6	2.5	2.2	1.8
Total debt/capital (incl intercompany loan)	54.6%	53.5%	57.9%	56.1%	59.8%
Cash flow/adjusted total debt (1)	17.5%	19.3%	15.3%	14.5%	9.1%
Cash flow/capital expenditures (times)	1.3	1.4	1.2	1.1	0.7
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.74%
Net income before extra items	212	240	217	190	127
Operating cash flow (CAD millions)	484	519	490	418	282

(1) Includes note receivable from parent company and investment in affiliate company

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Ratings Update (Continued from page 1.)

EGD's gas distribution margin declined modestly in 2010 by 2.9% but had increased year-over-year from F2006 through F2009 due to customer growth, favourable changes in customer mix and higher distribution rates as a result of the application to the IR formula approved by the OEB. In 2010, warmer weather was the primary driver of the modestly lower earnings when compared to 2009.

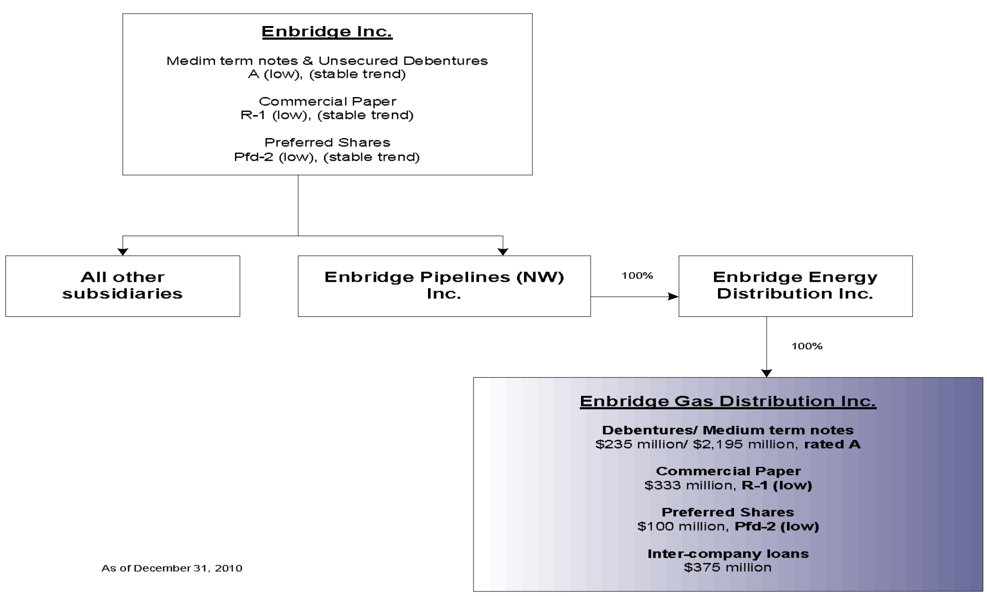
Customer growth however continues to be offset by lower average annual consumption. While the risk of fuel switching remains when natural gas prices are high (currently relatively low), natural gas is the predominant fuel of choice in the residential heating market in EGD's franchise area. Furthermore, natural gas has continued to provide price advantages over its primary competitors – domestic fuel oil and electricity.

For 2011, capital expenditures are expected to be approximately $500 million, having averaged $385 million annually in recent years, as the Company continues to invest in network expansion and upgrades to support customer growth, including lateral connections to new power generating facilities. Growth capex, which represents approximately 30% of capex, is expected to include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives.

As a portion of capital expenditures are financed through short-term debt and later refinanced with long-term debt, continued access to the short- and long-term capital markets is important for EGD. DBRS believes the Company's financing of these capital projects will be done in a manner that ensures it maintains stable credit metrics going forward. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain the stability of its credit profile and manage the regulatory approved capital structure.

The Company has very large and volatile seasonal liquidity requirements and usage of its credit facility remains high in the third and fourth quarter of the year as gas storage increases for the winter months. DBRS views the Company's current liquidity as adequate given the current low price gas environment, noting that a combination of cold weather and high gas prices could exhaust EGD's available liquidity.

Simplified Organizational Chart



Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Rating Considerations Details

Strengths
(1) EGD's low risk business operations continue to generate reasonably stable operating cash flows, while operating in a stable regulatory environment where the Company has the opportunity to recover its operating expenses and capital expenditures in a timely manner, and is allowed to earn a reasonable return on its investments. The Company has limited exposure to commodity price risk as its gas purchase costs are passed on to customers through quarterly rate adjustments. Furthermore, the long-term IR framework provides incentives for improved efficiency and long-term regulatory stability.

(2) EGD is the largest regulated natural gas utility in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. Modest and continued growth in its customer base will allow the Company to continue to generate strong earnings and cash flows.

(3) EGD maintains a reasonable balance sheet and credit metrics, reflecting: (a) total debt-to-capital ratio of 55%; (b) EBIT interest coverage ratio of 2.4 times; and (c) cash flow-to-debt ratio of 17.5%. The variability in cash flows and credit metrics year-over-year has been largely due to the impact of weather, seasonality of the gas distribution business and natural gas prices. The Company's credit metrics remain adequate for the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 36%.

(4) Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area and maintains both a price and environmental advantage relative to its primary competition, domestic fuel oil and electricity.

Challenges
(1) Weather remains the most significant risk, as forecast volumes, which are based on the normalized weather, are built into the Company's base rates, while actual usage varies with weather. Therefore, colder than normal weather would generally result in higher earnings compared to periods of warmer than normal weather. The years 2007 through 2009 were colder than normal and resulted in higher earnings for EGD when compared with 2010 which was warmer than normal.

(2) The Company has very large and volatile seasonal liquidity requirements, which has strained its available liquidity in the past. The Company's usage of its credit facility remains high in the third and fourth quarter of the year as gas storage increases for the winter months. As such, favourable access to the short- and long-term capital market remains important.

(3) Free cash flow deficits are expected to be modest over the medium term, mainly attributable to the Company's capital expenditures associated with unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives. EGD is expected to finance these deficits through debt issuances and management of dividend payments to (or equity injections from) the parent, so as to maintain the debt-to-capital ratio within the regulatory approved level of 64%.

(4) The IR framework has set a low base level for EGD's allowed ROE at 8.39% until year-end 2012. Thus, while the Company has the opportunity to earn higher returns, any upside is capped by the nature of the IR mechanism. Low ROEs have a negative impact on earnings and cash flow, although an increasing rate base would partially mitigate this impact.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Earnings and Outlook

	For the 12 months ended				
(CAD millions)	Dec. 10	Dec. 09	Dec. 08	Dec. 07	Dec. 06
Net gas distribution revenue	605	576	506	485	377
Gas transportation service revenue	390	449	505	500	493
Gas distribution margin	995	1,025	1,011	985	870
Other revenue	108	108	94	81	59
Total revenue	1,103	1,133	1,105	1,066	928
EBITDA (incl. income from affiliates)	729	761	746	707	586
EBIT (incl. income from affiliates)	459	507	507	479	373
Gross interest expense	189	195	206	214	207
Net income before extra. Items	212	240	217	190	127
Extraordinary items	(19)	(19)	(6)	0	0
Preferred dividends	(2)	(3)	(5)	(5)	(5)
Total	191	218	207	185	122
Return on equity	11.5%	12.9%	12.0%	11.2%	7.9%
EBIT margin	35.9%	39.2%	40.3%	39.0%	33.4%

Summary

- EGD's EBIT and EBITDA have remained stable over the past four years, and remained strong in 2010 primarily due to higher customer additions, favourable changes in customer mix and higher distribution charges, offset by warmer weather.
- EGD is expected to share excess earnings with customers under the current IR terms. The earnings sharing formula allows for earnings in excess of the annual adjusted ROE plus 100 basis points (bps) to be shared 50/50 with ratepayers. The Company's proportional estimate of earnings sharing was $19 million for 2010, subject to OEB approval in 2011.
- Transportation revenue has remained generally stable and represents 40% to 50% of the Company's gas distribution margins. EGD continues to monitor and take measures to mitigate potential weakness in the financial position of its large industrial customers.
- Interest expense has continued to decline modestly over the past few years with lower short-term borrowings as a result of lower gas prices.

Outlook

- The Company's earnings, under normal weather conditions, should grow moderately over the medium term, driven primarily by customer and economic growth in the Company's franchise areas and the continued competitiveness of natural gas. The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Though EGD's request to the OEB for approval to use the new base level ROE of approximately 9.85% to determine the annual earnings sharing with customers for 2010 and the remainder of the IR was denied, the Company anticipates applying the then-current ROE to determine rates after the conclusion of the IR terms, effective for the rate year beginning 2013. EGD has appealed the OEB ruling, with a decision pending.

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Financial Profile

Statement of Cash Flow	Dec 31	Dec 31	Dec 31	Dec 31	Dec 31
(CAD millions)	2010	2009	2008	2007	2006
Net income (after pfd dividends)	210	237	212	185	122
Depreciation & amortization	270	254	239	228	213
Non-cash charges & deferred income taxes	4	29	39	5	(53)
Cash Flow From Operations	484	519	490	418	282
Capital expenditures	(365)	(370)	(411)	(385)	(393)
Dividends to the parent	(208)	(181)	(158)	(65)	(175)
Free Cash Flow Before W/C Changes	(89)	(32)	(80)	(32)	(285)
Working capital changes	31	467	(125)	133	181
Net Free Cash Flow	(58)	436	(205)	101	(104)
Acquisitions/Divestitures	0	0	0	0	0
Other/adjustment	0	(14)	5	(12)	(30)
Cash flow before financing	(58)	422	(200)	89	(135)
Net change in debt financing	69	(470)	261	(167)	136
Net change in pfd equity financing	0	0	0	0	0
Net change in common equity	0	0	0	88	0
Other/adjustment	(16)	(21)			
Net change in cash flows	(5)	(68)	60	10	1

Key Figures and Ratios	Dec 31 2010	Dec 31 2009	Dec 31 2008	Dec 31 2007	Dec 31 2006
ST debt (millions)	500	677	1,026	826	831
LT debt (millions)	2,267	2,015	2,167	2,064	2,258
Inter-company debt ($ millions)	375	375	375	375	375
Total debt/capital (incl intercompany loan)	54.6%	53.5%	57.9%	56.1%	59.8%
Total debt/capital (excl. intercompany loan)	59.2%	58.1%	62.3%	60.8%	64.7%
EBIT interest coverage (incl. intercompany loan) (1)	2.4	2.6	2.5	2.2	1.8
EBIT interest coverage (excl. intercompany loan)	2.4	2.6	2.5	2.2	1.7
Cash flow/total adjusted debt (1)	17.5%	19.3%	15.3%	14.5%	9.1%
Cash flow/adjusted long-term debt (1)	20.0%	24.0%	21.6%	17.9%	12.5%
Dividend payout ratio	99.1%	76.6%	75.1%	36.9%	141.1%
Fixed charges coverage (times)	2.4	2.5	2.4	2.2	1.7

(1) Includes note receivable from parent company and investment in affiliate company.

Summary

- Cash flow from operations was sufficient to cover both dividends paid to the parent and estimated maintenance capital expenditures in 2009 and 2010. Credit metrics are expected to come under modest pressure from increasing capital expenditures.
- The Company's credit metrics remain consistent with the current rating category.
- EGD has a targeted dividend payment of 90% to 100% subject to maintaining a capital structure in line with regulatory levels.

Outlook

- DBRS expects EGD to generate modest free cash flow deficits due to capital expenditures in the medium term, which will be funded with a combination of debt and dividend management in order to maintain its credit metrics and manage the regulated approved capital structure.
- Capital expenditures (including growth) in 2011 are expected to increase to $500 million from current levels as the Company continues to invest in maintenance, network expansion and upgrades to support customer growth. Capital projects for 2011 include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives.
    - Deregulation of new natural gas storage has created a growth opportunity for EGD, as a result the Company expanded its storage capacity in 2010 by 8% and sold unregulated storage services into the storage market.

- EGD continues to have strong access to the short- and long-term capital markets. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain the stability of its credit metrics.

Long-Term Debt Maturities and Liquidity

Long Term debt (CAD millions)	Average Coupon	Maturity	Dec. 31, 2010	Dec. 31, 2009
Debentures	10.46%	2011-2024	235	385
Medium-term notes	5.54%	2011-2036	2,195	1,795
Other			6	12
Total long-term debt			2,436	2,192
Loans from affiliate			375	375

Debt Maturity schedule	Less than 1 year	1-3 years	3-5 years	Thereafter	Total
As at Dec. 31, 2010 (CAD millions)	150	0	400	1,880	2,430

- EGD's debt repayment schedule remains manageable, with only $150 million maturing within the next three years.
- As of December 31, 2010, EGD had issued $2,195 million of medium-term notes (MTNs) at an average coupon rate of 5.54%.
- EGD is subject to an EBIT interest covenant in order to issue additional indebtedness. EBIT for any 12 consecutive months out of the previous 23 months must be at least two times its annual pro forma interest requirements for all debt that has a maturity term longer than 18 months. The covenant does not apply to debt issuance for refinancing and interest expenses do not include short-term interest expenses. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. The Company was in compliance with the test at fiscal year end 2010.

Inter-company debt

- As of December 31, 2010, EGD owned $825 million of non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid by either cash or non-retractable preferred shares of the Company. DBRS treats this entire amount as debt and does not assign any equity treatment to the securities.

Bank Lines/Liquidity

Credit facilities	Amount	Drawn	Commercial Paper	Available	Expiry date (As at Dec. 31, 2010)
Committed lines of credit	700.0	0.0	350.0	350.0	Sep. 2011
Uncommitted lines of credit*	12.0	8.0	0.0	4.0	
Total	**712.0**	**8.0**	**350.0**	**354.0**	

* The uncommitted lines of credit are at St. Lawrence Gas.

(CAD millions)	Dec. 10	Sep. 10	Jun. 10	Mar. 10	Dec. 09
Short term debt usage	350	445	157	260	527

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capital expenditures. Working capital requirements are very seasonal and are also heavily influenced by the volatility of gas prices. These fluctuating capital requirements are mainly supported by the Company's commercial paper (CP) program.

- The Company has a $700 million CP program of which $350 million was available at the end of 2010. The CP program is fully backed by a $700 million 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate, given the current low gas price environment; nevertheless, the Company remains exposed to gas price volatility. A combination of cold weather and high gas prices could exhaust the Company's available liquidity, however, this is unlikely given the relatively current low gas price environment.

Regulation

Regulatory Overview
The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly rate adjustments. Therefore, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution
In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan to a maximum of an additional two years.

This IR methodology adjusts revenues every year, not rates, and relies on an annual process to forecast volume and customer additions. Unlike the Cost of Service methodology utilized in prior years, the concepts of rate base and return on rate base are not relevant for the purpose of setting rates. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The Company's 2010 ROE of 8.39% will remain unchanged throughout the IR period. The equity component also remains at 36%. The gas commodity and upstream transportation costs will continue to be passed on to customers.

The OEB recently reviewed the current methodology for adjusting cost of capital for regulated entities starting in the 2010 rate year. The decision maintains a formulaic approach to setting ROE levels; however, the existing formula will be reset to address the relatively low current ROE level, and refined to reduce sensitivity to changes in government bond yields. This new approach will provide an initial ROE of 9.75% (since revised to 9.58%) to be incorporated in 2010 Cost of Service applications. For EGD, the full benefit of the higher allowed ROE is expected to be captured on renewal of the IR in 2013. In January 2011, the Ontario Division Court heard EGD's appeal of the OEB's decision not to adjust the 8.39% ROE in its IR settlement to the revised 9.75% regulated ROE for the purposes of EGD's IR earnings sharing formula. The sharing formula allows earnings in excess of the annual adjusted ROE, plus 100 bps, to be shared 50/50 with ratepayers. The Division Court decision is pending.

The key terms of the OEB approved IR framework (effective January 2008) are summarized as follows:

- *Revenue Per Customer Cap* – The settlement allows for the annual reset of volumes, with revenues increasing proportionately with the growth in the number of customers. The revenue per customer cap will continue to minimize the Company's exposure to declining average use of natural gas while providing an incentive for the Company to continue growing its customer base.

- *Revenue Escalation Factor* – The revenue escalation factor is comprised of an inflation component and an adjustment for customer growth. In addition to the annual inflation adjustment, revenues will also grow by the annual increase in the number of customers. Based on an assumed inflation rate of 2%, the combined inflation and growth factors is forecast to result in an overall revenue escalation averaging approximately 3% per year through the term of the plan.

- *Earnings Sharing* – To align the interests of customers with the Company's shareholders, an earnings sharing mechanism forms part of the settlement. To the extent the actual utility return on equity represented by normalized earnings (i.e., excluding the effects of weather) exceeds the allowed utility return on equity (adjusted in accordance with provisions in the IR agreement), earnings will be shared with customers. The shareholders will retain the first 100 bps of ROE above the allowed ROE, while earnings represented by the ROE in excess of 100 bps above the allowed ROE will be shared equally with customers.

- *Adjustments* – There are several cost and deferral accounts that fall outside of the revenue escalation formula. The settlement provides for the recovery of capital invested in new power generation laterals, which is important given the significant capital requirements for such projects and their importance to Ontario's electricity needs. The Company is also allowed to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

- *Off Ramps* – An OEB review will be triggered if the Company's ROE varies more than 300 bps (either negatively or positively) relative to the allowed ROE. The review will determine the reasons for the variance in earnings and in such circumstances could result in adjustments to the settlement or a return to Cost of Service regulation. The review will not have an impact on earnings for prior years. The settlement does not preclude the Company from applying to the OEB for an increase in the embedded allowed ROE.

Gas Storage

EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB changed EGD's pricing policy in 2007.

Gas Distribution – New York

The Company owns St Lawrence Gas Company, which provides natural gas distribution services to 15,000 customers in New York State. The regulatory framework in New York is viewed as stable.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

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Enbridge Gas Distribution Inc.

Balance Sheet
(CAD millions)

Assets	Dec. 31 2010	Dec. 31 2009	Dec. 31 2008	Liabilities & Equity	Dec. 31 2010	Dec. 31 2009	Dec. 31 2008
Cash + equivalents	-	-	100	S.t. & l.t.d. due 1yr.	500	677	1,026
Accounts receivable	802	769	980	A/P, accr'ds. & other	841	786	755
Gas in storage	400	396	656	**Current Liabilities**	1,341	1,463	1,781
Other current assets	-	33	23	Def'd. taxes + credits	1,229	1,157	14
Current Assets	1,202	1,197	1,759	Long-term debt	2,267	2,015	2,167
Net fixed assets	4,458	4,290	3,514	Loans from affiliate	375	375	375
Other assets	654	666	186	Perpetual pfds.	100	100	100
Investments in affiliate	825	825	825	Shareholders' equity	1,827	1,867	1,848
Total	7,139	6,978	6,285	**Total**	7,139	6,978	6,285

Ratio Analysis	Dec 31	Dec 31	Dec 31	Dec 31	Dec 31
Liquidity Ratios	2010	2009	2008	2007	2006
Current ratio	.90x	.82x	.99x	.98x	1.08x
Accumulated depreciation/gross fixed assets	25.5%	25.0%	36.0%	35.6%	34.7%
Cash flow/capital expenditures	1.33x	1.40x	1.19x	1.09x	0.72x
Cash flow-dividends/capital expenditures	0.76x	0.91x	0.81x	0.92x	0.27x
Cash flow/adjusted debt (1)	17.5%	19.3%	15.3%	14.5%	9.1%
Total debt/capital (incl intercompany loan)	54.6%	53.5%	57.9%	56.1%	59.8%
Total debt/capital (excl. intercompany loan)	59.2%	58.1%	62.3%	60.8%	64.7%
Deemed equity	36%	36%	36%	36%	35%
Dividend payout ratio	99.1%	76.6%	75.1%	36.9%	141.1%
Coverage Ratios					
EBITDA interest coverage (1)	3.86x	3.91x	3.63x	3.31x	2.83x
EBIT interest coverage (1)	2.43x	2.60x	2.46x	2.24x	1.80x
Fixed-charges coverage	2.39x	2.54x	2.38x	2.16x	1.74x
Debt/EBITDA	3.80x	3.54x	4.28x	4.09x	5.27x
Earnings Quality/Operating Efficiencies & Statistics					
Operating margin	35.9%	39.2%	40.3%	39.0%	33.4%
Net margin	19.2%	21.2%	19.7%	17.8%	13.7%
Return on common equity	11.5%	12.9%	12.0%	11.2%	7.9%
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.74%
Degree day deficiency - % normal	97.7%	107.2%	107.3%	101.2%	89.6%
Customer growth	2.0%	2.0%	2.0%	2.3%	3.7%

(1) Includes note receivable from parent company and investment in affiliate company.

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2010	2009	2008	2007	2006
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Notes:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
June 28, 2012

Previous Report
April 4, 2012

Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,500 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly owned subsidiary of Enbridge Inc. (rated A (low)).

Commercial Paper Limit:
$700 million

Rating

Debt	Rating	Trend
Commercial Paper	R-1 (low)	Stable
Unsecured Debentures & Medium-Term Notes	A	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Stable

Ratings Update

The credit profile of Enbridge Gas Distribution Inc. (EGD or the Company) has remained stable in Q1 2012, based on the latest financial results and regulatory development. The Company's rating is based on its low business risk operations, stable regulatory environment in Ontario, strong franchise area and stable financial profile.

EGD's low business risk profile is supported by a large customer base (approximately two million customers, the largest in Canada), which has allowed the Company to achieve operational efficiency and generate earnings in excess of approved return on equity (ROE) under the incentive regulation (IR) framework since 2008. The Company benefits from a stable regulatory system, having no exposure to gas price risk in Ontario, where it generates approximately 98% of its revenues. EGD's franchise area (largely in the Greater Toronto Area) is viewed as one of the most rapidly growing and economically strong service areas in Canada. Approximately 95% of the Company's earnings are contributed by relatively stable regulated distributions, transportation and storage, with the remainder contributed by unregulated storage business, which benefits from strong demand, due to its strategic locations. EGD will be under the cost-of-service (COS) year in 2013, which is expected to provide it an opportunity to obtain a larger rate base, higher allowed ROE (currently 8.39%) and higher deemed equity (currently 36%).

EGD's financial profile continued to remain stable in Q1 2012, with all credit metrics being commensurate with DBRS's "A" rating guidelines. DBRS notes that the Company requires significant liquidity to finance working capital (mostly gas inventory for winter distributions). Given the low gas price environment, EGD's liquidity remains adequate to meet its operational needs. Over the medium term, moderate cash flow deficits are expected, due to a large capex program. However, EGD's current debt leverage is well below the regulatory capital structure of 64% debt/36% equity, providing EGD with significant financial flexibility. DBRS expects the Company to remain prudent in funding its cash shortfalls and maintaining its credit metrics within the "A" rating category.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics

Challenges
(1) Weather-related volume risk
(2) Low ROE and limited rate base growth
(3) Cash flow deficits

Financial Information

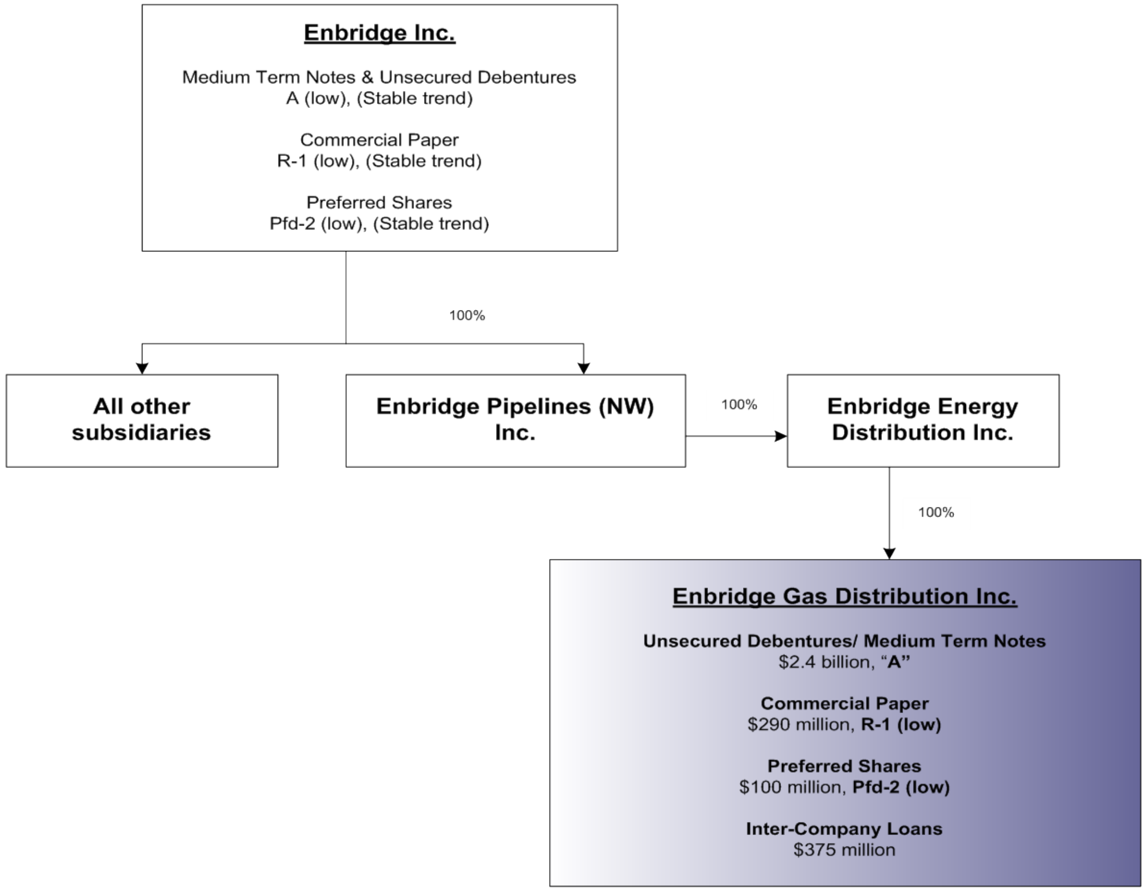
	USGAAP	USGAAP	MIX	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Enbridge Gas Distribution Inc.	**3 mos. Mar 31**		**12 mos. Mar. 31**	**For the year ended December 31**				
(CA$ millions)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. Items	73	104	180	211	193	221	211	190
Cash flow from operations	153	176	474	497	467	504	483	423
Total debt in capital structure (1)	49.2%	52.0%	49.2%	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT gross interest coverage (times) (1)	2.95	3.78	2.40	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	26.4%	32.8%	20.4%	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/EBITDA (times) (1)	2.86	2.16	3.75	3.85	3.59	3.32	4.12	3.90
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company prefered dividend income and interest expense.

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Simplified Organizational Chart (1)



(1) Debt information as of March 31, 2012.

Rating Considerations Details

Strengths

(1) **Low business risk, stable regulatory framework.** EGD's low risk business is underpinned by its gas distribution operations and a stable regulatory environment. Gas supply costs are adjusted quarterly and are passed through to customers. Currently, the Company operates under a long-term IR framework until 2013, which provides incentives for improved efficiency and long-term regulatory stability.

(2) **Strong franchise, large customer base.** EGD is the largest regulated natural gas distributor in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong. The size of the customer base allows the Company to achieve operational efficiency. EGD has generated returns on approved equity levels in excess of 100 basis points of approved ROE over the past four years.

(3) **Reasonable balance sheet and credit metrics.** EGD maintains a reasonable balance sheet and strong credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt/36% equity. The current debt leverage (56%) provides the Company with significant financial flexibility.

Challenges

(1) **Volume risk due to weather.** Weather remains the most significant risk, as forecast volumes – based on the normalized weather – are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder weather than normalized weather in the forecast generally results in higher earnings compared to periods of warmer than normalized weather.

(2) **Limited rate base growth and low ROE during the IR period.** Until the next COS application expected in 2013, the rate base growth will be limited and the relatively low current approved ROE of 8.39% will not be changed.

(3) **Free cash flow deficits.** Free cash flow deficits almost doubled in 2011 to $198 million as a consequence of increased dividend and growing capex. Negative free cash flow is expected to continue in 2012, since capex is expected to remain high. While incremental cash flow is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million), cash contributions from these power projects will be very modest.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Earnings and Outlook

(CA$ millions)	USGAAP 3 mos. Mar 31 2012	USGAAP 3 mos. Mar 31 2011	MIX 12 mos. Mar. 31 2012	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net gas distribution revenue	198	193	674	669	605	576	506	485
Gas transportation service revenue	93	140	305	352	390	449	505	500
Gas distribution margin	291	333	979	1,021	995	1,025	1,011	985
Other revenue	29	28	105	104	108	108	94	81
Total revenue	320	361	1,084	1,125	1,103	1,133	1,105	1,066
EBITDA	203	249	619	665	666	699	684	644
EBIT	124	174	334	384	396	445	445	416
Earnings sharing	6	6	13	13	19	19	6	0
Intercompany dividend income	0	0	0	(27)	(27)	(27)	(27)	(27)
Interest expense (external)	(42)	(46)	(139)	(143)	(151)	(155)	(175)	(159)
Interest expense (intercompany)	16	16	63	63	63	63	63	63
Net income before extra. Items	73	104	180	211	193	221	211	190
Extra items	0	0	0	0	0	0	0	0
Reported net income	73	104	180	211	193	221	211	190
Deemed equity (EGD)	36%	36%	36%	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%
Actual ROE	13.50%	21.08%	8.22%	10.79%	9.91%	11.32%	11.06%	10.58%

Summary

- The Company's earnings are contributed mainly by gas distribution operations (approximately 59% of 2011 net revenue) and gas transportation operations (31% of net revenue), with the remaining contributed by the storage business.
- Most earnings from gas distribution operations are generated by EGD, with a small portion (about 2% of revenues) contributed by its wholly-owned St. Lawrence, a natural gas distributor in New York State.
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 5% of overall earnings (DBRS estimates).
- Earnings in regulated operations are mainly driven by rate base growth and approved ROE (both of which remained stable in 2011), as well as weather, which in 2011 was colder than 2010 and was largely responsible for a slight increase in earnings.
- DBRS notes that transportation revenue has declined since 2007, due to a gradual decrease in volumes.
- Earnings sharing represents EGD's 50% share of the actual return on the approved equity level (excluding the effect of weather), in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million inter-company loan outstanding at December 31, 2011. The interest expense on this loan was $27 million in 2011.

Outlook

- The Company's earnings, under normal weather conditions, should increase moderately in 2012, driven primarily by customer growth in the Company's franchise areas.
- The rate base and ROE are not expected to change until 2013, the rebasing year for EGD.
- The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Earnings growth is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million). However, the earnings contribution from these power projects will be very modest.

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Financial Profile

	USGAAP	USGAAP	MIX	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Consolidated Cash Flow Statement: EGD	**3 mos. Mar 31**		**12 mos. Mar. 31**	**For the year ended December 31**				
(CA$ millions)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. items	73	104	180	211	193	221	211	190
Depreciation & amortization	79	75	285	281	270	254	239	228
Deferred income taxes/Other	1	(3)	9	5	4	29	33	5
Cash flow from operations	153	176	474	497	467	504	483	423
Dividends paid	(56)	(55)	(221)	(220)	(210)	(185)	(163)	(70)
Capex	(88)	(64)	(499)	(475)	(365)	(370)	(411)	(385)
Free cash flow before WC	9	57	(246)	(198)	(108)	(51)	(91)	(32)
Changes in working capital (WC)	274	263	28	17	45	467	(115)	136
Net free cash flow	283	320	(218)	(181)	(63)	416	(207)	103
Acquisitions (2)	0	0	0	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	0	0	0	0
Net changes in equity (2)	0	0	0	0	0	0	0	88
Net changes in debt	(266)	(227)	135	174	69	(469)	261	(167)
Other	(5)	(35)	33	3	(13)	(15)	6	(14)
Change in cash	12	58	(50)	(4)	(7)	(68)	60	10
Total external debt ($ millions)	2,319	2,148	2,319	2,562	2,391	2,318	2,818	2,514
Inter-company debt ($ millions)	375	375	375	375	375	375	375	375
Total debt/Capital (1)	49.2%	52.0%	49.2%	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT interest coverage (times) (1)	2.95	3.78	2.40	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	26.4%	32.8%	20.4%	19.4%	19.5%	21.7%	17.1%	16.8%
Dividends/Cash flow	35.9%	30.7%	46.2%	43.9%	44.5%	35.9%	32.7%	15.4%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.

(2) In August 2011, EGD issued $66 million to finance its $66 million solar asset acquisition from Enbridge Inc.

Summary

- Higher earnings and higher depreciation contributed to increased cash flow from operations. However, in 2011, free cash flow deficits increased as a result of increased dividends and large capex.
- Higher capex in 2011 was mainly due to its customer care system and unregulated storage expansion.
- EGD has a targeted dividend payment of 90% to 100%, subject to maintaining a capital structure in-line with regulatory levels.
- Despite debt financing, the Company’s capital structure remained stable and was well within the regulatory capital structure of 36% equity.
- Other key credit metrics: EBIT-interest coverage and cash flow-to-debt ratio remained stable and were in line with the “A” rating category.
- The Company issued $66 million in equity to finance its $66 million acquisition of solar assets from Enbridge Inc. However, due to the nature of inter-company transaction, the issuance of equity did not record in the cash flow statement in 2011, though the equity base increased by $66 million.

Outlook

- Capex for 2012 is expected to be approximately $440 million on capital projects and maintenance. Capital projects largely include the iron cast replacement program, construction of the technical training program and power generation.
- As a result, the Company is expected to generate free cash flow deficits of approximately $160 million in 2012. DBRS expects EGD to remain prudent in its financing of the cash shortfalls in order to maintain its balance sheet leverage within “A” rating guidelines.

Long-Term Debt Maturities and Liquidity

Bank Lines/Liquidity

Credit Facilities			As at Mar. 31, 2012
	Total Facilities	Drawn	Available
Committed lines of credit	700	280	420
Uncommitted lines of credit*	12	9	3
Total	712	289	423

* The uncommitted lines of credit are at St. Lawrence Gas, Inc.

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capex.
- Working capital requirements are very seasonal and heavily influenced by the volatility of gas prices.
- EGD has a $700 million CP program, of which $420 million was available at the end of March 2012. The CP program is fully backed by a $700 million, 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate. Nevertheless, a combination of cold weather and high gas prices could exhaust the Company's available liquidity. However, this scenario is unlikely, given the current low gas price environment.

Debt	As at Mar. 31, 2012 (CAD millions)
Commercial paper	280
Other ST borowings	27
LT debt	2,387
Total	**2,694**

Long-Term Debt Maturity schedule	<1 year	1-3 years	3-5 years	Thereafter	Total
As at Dec. 31, 2011 (CAD millions)	-	400	-	1,974	2,374

- Refinancing the debt is still manageable, despite $400 million of debt due in the coming three years.
- In April 2011, EGD repaid its $150 million of 10.80% debentures. The Company then issued $100 million medium-term notes at 4.95%, as well as additional draws on its credit facilities at lower interest rates. The company took the opportunity of a low interest rate environment to refinance, lowering interest expense for future years.
- EGD is subject to an EBIT interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
- The covenant does not apply to debt issuance for refinancing.
- The Company was in compliance with the test at fiscal year-end 2011 and Q1 2012.

Inter-company debt

- As of March 31, 2012, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.

Regulation

Regulatory Overview

The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution: Ontario

- In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan, to a maximum of an additional two years.
- Revenue escalation adjusts distribution revenues every year (50% of inflation in 2011 and 45% inflation in 2012), relying on an annual process to forecast volume and customer additions.
- The Company is allowed to have several costs and deferred accounts outside of revenue escalation formulae, including capex invested in new power generation and expenses above a defined threshold.
- The Company's 2011 ROE of 8.39% and deemed equity of 36% will remain unchanged until 2013.
- EGD will retain earnings in excess of the approved ROE up to 100 basis points and will share equally with customers the actual return on the approved equity level (excluding the effects of weather) in excess of 100 basis points above the approved ROE.
- In September 2011, EGD filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The OEB approved $1,004 million for 2012, or 98% of the requested amount. The rate adjustment was effective January 1, 2012.
- A hearing with respect to the remaining amount of $20 million (or 2%) was held by the OEB in January 2012, with a decision expected by April 2012.
- In January 2012, the Company filed a COS application for 2013, requesting distribution revenue of $1,102 million. A decision on this application is expected later in 2012.

Gas Distribution: New York

- The Company owns St. Lawrence Gas Company (SLG), which provides natural gas distribution services to 15,500 customers in New York State.
- The regulatory framework in New York is under cost of service and is viewed as stable. The approved ROE for 2011 was 10.5% on a deemed equity of 50%. Any earnings above 11% will be shared equally with customers. SLG had no earnings sharing in 2011 and 2010.
- Gas supply costs are adjusted annually.

Gas Storage

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB's change of EGD's pricing policy in 2007.

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Enbridge Gas Distribution Inc.

Balance Sheet (CA$ millions)	USGAAP Mar. 31 2012	CGAAP Dec. 31 2011	CGAAP Dec. 31 2010		USGAAP Mar. 31 2012	CGAAP Dec. 31 2011	CGAAP Dec. 31 2010
Assets				**Liabilities & Equity**			
Cash & equivalents	21	9	13	S.T. borrowings	307	563	349
Accounts receivable	531	402	457	Current portion L.T.D.	0	0	150
Inventories	125	380	400	Accounts payable	579	67	57
Others	0	261	345	Deferred tax	2	2	5
				Others	0	646	793
Total Current Assets	**677**	**1,052**	**1,215**	**Total Current Liabilities**	**888**	**1,278**	**1,354**
Net fixed assets	5,418	4,770	4,458	Long-term debt (L.T.D.)	2,387	2,374	2,267
Future income tax assets	0	0	0	Deferred income taxes	312	178	171
Goodwill & intangibles	179	179	167	Other L.T. liabilities	1,416	1,502	1,433
Investments & others	1,127	1,314	1,312	Preferred shares	100	100	100
				Shareholders equity	2,298	1,883	1,827
Total Assets	**7,401**	**7,315**	**7,152**	**Total Liab. & SE**	**7,401**	**7,315**	**7,152**

Balance Sheet & Liquidity & Capital Ratios	USGAAP 3 mos. Mar 31 2012	USGAAP 3 mos. Mar 31 2011	MIX 12 mos. Mar. 31 2012	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Current ratio (times)	0.76	0.92	0.76	0.82	0.90	0.61	0.66	0.98
Total debt in capital structure	52.9%	56.0%	52.9%	59.7%	58.9%	57.8%	62.2%	60.5%
Cash flow/Total debt	5.7%	7.0%	17.6%	16.9%	16.9%	18.7%	15.1%	14.6%
Cash flow/Capex (times)	1.74	2.75	0.95	1.05	1.28	1.36	1.17	1.10
(Cash flow - Dividends)/Capex (times)	1.10	1.89	0.51	0.58	0.70	0.86	0.78	0.92
Dividend payout ratio	76.7%	52.9%	122.8%	104.3%	108.8%	83.7%	77.2%	36.9%
Dividends/Cash flow	35.9%	30.7%	46.2%	43.9%	44.5%	35.9%	32.7%	15.4%
Profitability Ratios								
EBITDA margin	23.3%	27.4%	25.5%	27.0%	26.9%	24.1%	22.0%	21.8%
EBIT margin	14.2%	19.1%	13.8%	15.6%	16.0%	15.3%	14.3%	14.1%
Profit margin	8.4%	11.4%	7.4%	8.6%	7.8%	7.6%	6.8%	6.4%
Return on equity	13.5%	21.1%	8.2%	10.8%	9.9%	11.3%	11.1%	10.6%
Return on capital	8.2%	11.7%	5.6%	6.4%	6.3%	6.6%	6.5%	6.0%
Allowed ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.5%	10.5%	10.5%	10.5%	10.5%			
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense								
Cash flow/Debt	26.4%	32.8%	20.4%	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/Capital	49.2%	52.0%	49.2%	56.4%	55.4%	54.1%	59.3%	57.1%
EBITDA gross interest coverage (times)	4.83	5.41	4.45	4.65	4.41	4.51	3.92	4.06
EBIT gross interest coverage (times)	2.95	3.78	2.40	2.69	2.62	2.87	2.55	2.62
Debt/EBITDA (times)	2.86	2.16	3.75	3.85	3.59	3.32	4.12	3.90

Enbridge Gas Distribution Inc.

Report Date:
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Rating

Debt Rated	Rating	Trend
Commercial Paper	R-1 (low)	Stable
Unsecured Debentures & Medium-Term Notes	A	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Stable

Rating History

Debt Rated	Current	2011	2010	2009	2008	2007
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Note:
All figures are in Canadian dollars unless otherwise noted.

SEC INTERROGATORY #8

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/2/1, p. 30

Please provide a table listing, for each of the companies in the proxy group referred to, the actual equity thickness of the company for each year from 1993 to date, and on the same table the actual equity thickness for the Applicant for each of those years.

RESPONSE

Concentric lacks the data required to fully comply with the requested analysis (actual equity thickness of each proxy group company from 1993 to date). The time required to obtain such historical data would extend beyond the due date of this response. However, Concentric has assembled the analysis to the fullest extent possible. That analysis may be found in Attachment 1.

Note that these calculations of actual common equity differ from the computation of common equity found at Exhibit E2, Tab 2, Schedule 1, Concentric-02, in that preferred equity is included in the attached in the denominator of the equity thickness computation, whereas (as noted on Concentric-02) preferred equity was excluded from both the numerator and the denominator of the common equity computation.

Witnesses: R. Fischer
M. Lister

Common Equity Thickness

Year	[1] Atlanta Gas Light Company	[2] Brooklyn Union Gas Company	[3] Northern Illinois Gas Company	[4] Piedmont Natural Gas Company, Inc.	[5] Questar Gas Company	[6] Southern California Gas Company	[7] Washington Gas Light Company	[8] Enbridge Gas Distribution Inc.	[9] Atco Gas (CU Inc.)	[10] FortisBC Energy Inc.	[11] Union Gas Ltd.
2011	52.48%	49.56%	38.65%	42.02%	46.97%	61.99%	58.28%	39.97%	39.00%	50.88%	36.13%
2010	52.88%	52.21%	38.66%	43.53%	44.34%	55.00%	57.89%	40.93%	39.00%	50.31%	35.92%
2009	50.32%	50.47%	38.55%	41.91%	46.61%	57.64%	55.54%	37.18%	38.75%	34.85%	38.88%
2008	48.69%	50.85%	33.77%	37.50%	45.63%	51.52%	49.59%	33.65%	37.33%	34.79%	35.72%
2007	49.35%	54.92%	41.23%	40.10%	46.89%	56.14%	51.06%	34.70%	37.95%	34.80%	38.27%
2006	50.36%	51.38%	42.03%	43.04%	49.50%	56.49%	53.02%	31.13%	35.80%	36.63%	36.41%
2005	50.69%	46.41%	38.40%	45.99%	44.29%	53.36%	50.45%	32.22%	37.42%	33.69%	36.02%
2004	49.45%	47.92%	40.57%	49.57%	46.10%	60.27%	53.37%	34.84%	35.27%	34.23%	37.13%
2003	72.81%	47.97%	35.53%	37.40%	47.47%	58.55%	51.09%	36.84%	33.40%	31.59%	36.87%
2002	61.01%	57.49%	41.00%	50.10%	49.40%	60.69%	49.18%	48.71%	NA	32.10%	30.52%
2001	56.33%	61.55%	44.17%	50.09%	46.53%	63.37%	47.28%	46.16%	NA	31.58%	28.69%
2000	46.14%	54.23%	39.71%	46.10%	44.40%	56.89%	44.86%	39.59%	NA	32.70%	30.40%
1999	50.01%	57.42%	44.71%	49.10%	46.40%	56.16%	49.69%	37.99%	NA	36.81%	30.25%
1998	47.05%	59.56%	46.08%	51.88%	41.39%	55.74%	51.68%	29.45%	NA	38.35%	33.02%
1997	41.18%	57.37%	44.26%	50.61%	40.61%	46.40%	50.02%	32.51%	NA	36.90%	32.77%
1996	38.80%	57.52%	44.20%	46.79%	45.79%	46.24%	50.58%	31.82%	NA	36.20%	30.94%
1995	45.58%	55.92%	49.99%	48.00%	46.92%	NA	54.47%	31.56%	NA	NA	NA
1994	41.70%	55.01%	48.26%	44.45%	46.67%	NA	51.21%	NA	NA	NA	NA
1993	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Sources:
[1], [2], [3], [4], [5], [6], [7] Gas LDC filing data compiled by SNL Financial; equals (Total Proprietary Capital − Preferred Stock Issued) / (Total Proprietary Capital + Total Long-Term Debt + Notes Payable + Notes Payable to Associated Companies)
[8], [10], [11] System for Electronic Document Analysis and Retrieval (SEDAR)
[9] Alberta Utilities Commission, Rule 005 filings

VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E2 Tab 1 Schedule 2

Preamble: The Board's draft (cost of Capital) Guidelines assume that the base capital structure will remain relatively constant over time and that a full re assessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk (page 50).

a) Please provide an extract and reference to the Settlement and/or the Decision approving the current common equity ratio for EGD.

b) Please provide the percentage of total distribution revenue from fixed charges, and firm demand charges at the time of the increase in equity thickness and in-2013.

c) Explain why the following do not serve to reduce EGDIs Business Risk relative to:
   a. the period prior to their implementation and
   b. relative to other Utilities

      i. AUTUVA
      ii. LRAM/LRAMVA

d) How many of Canadian and US utilities in the sample have

      i) General Service declining use protection (AUTVA)
      ii) LRAM protection and
      iii) Are/are not exposed to weather risk

Please provide a chart that shows these attributes on a comparable basis.

e) Confirm that EGDI (and EI) is also compensated for Conservation efforts via the SSM and provide the Annual amounts 2007-2011 earned by the shareholder.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

f) Contrast the SSM amounts earned by EGDI to those of Hydro One Distribution over the same period.

RESPONSE

a) The current common equity ratio for EGD was established for the 2007 test year (EB-2006-0034), and was the result of a Decision. The following is an extract from that decision. For the complete reference, please see the Decision with Reasons – Phase 1, July 2007, p.p. 62-66.

> "In consideration of all of the above, and on balance, the Board finds an increase in the common equity thickness from 35% to 36% to be reasonable."

The Board further stated:

> "While Union's current 36% common equity was the result of a negotiated settlement, Enbridge's proposal for a 38% common equity level is materially higher than Union's, which is not consistent with the relative business risk profile of the two utilities."

EGD notes that while Union may have been satisfied with the negotiated trade-off that resulted in the currently 36% equity ratio, that Union is no longer satisfied that a 36% equity ratio is appropriate for its business conditions, as evidenced by their request for an increase in equity thickness to 40% for the 2013 test year.

b) Equity thickness increased from 35% to 36% in 2007. In 2007, the amount of distribution revenue recovered from fixed charges was 33%. For 2013, the amount of fixed charge recovery is forecast to be 51%.

c) Please refer to Appendix B of the Concentric Report, pages B-2 through B-6 for a discussion of business and operating risks and how they may be addressed in the regulatory framework. Specifically, EGDI's AUTUVA and LRAM serve to reduce the emerging risks of declining gas use per customer and that from conservation, but do

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

not protect the company from fluctuations due to weather, and accordingly do not warrant the full credit for risk mitigation enjoyed by many of the other proxy companies. The LRAM was introduced as a mechanism to remove the potential incentive barrier in the pursuit of conservation and to provide for a true up for intra-year variances, so that both the Company and ratepayers are not negatively impacted from variances to the forecast. Though these mechanisms have undoubtedly reduced the volumetric risk of EGDI compared to before their implementation, such mechanisms have become the norm for a gas utility and are more likely to raise capital costs by their absence than to reduce capital costs by their presence. The AUTUVA and LRAM are specifically discussed on page B-4.

d) Please refer to part (c) above. Figure 10, on page B-3 of Appendix B, compares revenue stabilization mechanisms employed by EGDI (LRAM and AUTUVA) to those employed by the proxy group. As Figure 10 shows, all of the other members of the comparable group employ the same or better protection against volumetric risk due to weather, declining use or conservation as does EGDI. Any company with a solid ball in the “Revenue Stabilization” category would be deemed to satisfy the three listed attributes, i.e. are immune to volumetric risk, whether it be due to conservation, declining use, or weather. A partial ball would indicate that the company remains exposed to volumetric risk, either due to weather or due to declining use. Page B-5 discusses to what extent volumetric risk is mitigated by the comparable group. For example, volumetric risk may be mitigated by straight-fixed variable rate design; a conservation mechanism used in concert with a weather normalization mechanism, or a full decoupling mechanism. A brief description of what sort of rate stabilization mechanisms each comparable company employs is included on page B-5.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

e) EGDI earns a financial incentive (SSM) to recognize performance against set annual Demand Side Management targets. The 2007 – 2011 SSM amounts were as follows:

2007 – $8.25 M
2008 – $5.80 M
2009 – $5.36 M
2010 – $4.16 M
2011* – $6.69 M

*Per Audit report as at July 11, 2012 and subject to clearance of accounts and Ontario Energy Board approval.

f) EGD is not able to produce the Hydro One SSM results.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

VECC INTERROGATORY #2

INTERROGATORY

E- Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E2 Tab 1 Schedule 2

Preamble: Concentric notes that EGDI's interest coverage as calculated by S&P for the year ended 2010 was 2.3x, which places EGDI very close to losing access to capital under its trust indenture. Based on S&P's 2010 data swing in EGDI's gas distribution revenues of only 3 percent would be sufficient to decrease its EBIT/Interest Coverage.

a) Please provide the Reference(s) and if not public, an extract.

b) Please provide a Chart that shows key Financial Ratios for EGDI (utility only if possible) and for Enbridge Inc for the years 2007-2012.

c) Provide references to data sources.

RESPONSE

a) The referenced calculation in the preamble is a Concentric calculation, based on the same adjustments to the 2010 EGDI financial data (per the EGDI Consolidated Financial Statements, as of December 31, 2010) that S&P applied in its December 29, 2010 credit report for EGDI, per the Standard and Poor's, Ratings Direct - Global Credit Portal. That calculation is shown on the following page as well as the calculation showing the impact of a 3% reduction in revenue. Concentric's calculation indicated that if all else remained the same and revenue decreased by 3%, the interest coverage ratio would fall to 2%, i.e. calculation follows:

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister
D. Yaworski

Manual Calculation	**2010**	**2009**	**2008**
Funds from operations (FFO)			
Cash flow from operations (reported)	503.0	971.3	367.7
Capitalized interest	(3.0)	(5.7)	(5.1)
Reclassification of working-capital	(31.0)	(467.3)	115.4
	469.0	498.3	478.0
Interest expense			
Interest expense (reported)	186.0	189.1	200.8
Capitalized interest	3.0	5.7	5.1
	189.0	194.8	205.9
FFO interest coverage (x)	**3.5**	**3.6**	**3.3**
Debt			
Gas inventories	(400.0)	(395.7)	(656.3)
Bank overdraft	18.0	12.8	44.6
Short-term borrowings	332.0	514.5	881.6
Current maturities of long-term debt	150.0	150.0	100.0
Long-term debt	2,267.0	2,015.4	2,167.1
Loans from affiliate company	375.0	375.0	375.0
	2,742.0	2,672.0	2,912.0
FFO/debt (%)	**17.1%**	**18.6%**	**16.4%**
Shareholders' equity	1,927.0	1,967.3	1,937.7
Debt/debt and equity (%)	**58.7%**	**57.6%**	**60.0%**
EBITDA	**Calculated from**	**3% Reduction in Revenue**	
Revenue			
Gas Commodity and Distribution Revenue	**1,977.0**	**1,917.7**	
Transportation of Gas for Customers	390.0	390.0	
Gas Commodity and Distribution Costs Excl. De	(1,372.0)	(1,372.0)	
Other Revenue	108.0	108.0	
Affiliate Financing Income	63.0	63.0	
Expenses			
Operating and Administrative	393.0	393.0	
Municipal and Other Taxes	44.0	44.0	
Earnings Sharing	19.0	19.0	
	710.0	650.7	
Regulated Asset Value (Rate Base)	3,837.7	3,837.7	
Debt/Regulated Asset Value	**81.9%**	**81.9%**	
EBIT interest coverage (x)			
Depreciation and Amortization	270.0	270.0	
EBIT (see EBITDA calc. above)	440.0	380.7	
	2.3X	**2.0X**	

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister
D. Yaworski

b) Below is a table of key financial metrics for EGDI and EI from 2007 – 2011 (there is no data for 2012). This data was accessed through SNL, and is based on Company consolidated financial statements.

		2007	2008	2009	2010	2011	
Enbridge Gas Distribution Inc.							
	EBIT/Interest Coverage	2.50	2.40	2.50	2.50	2.50	
	Debt/EBITDA	3.60	3.70	3.60	3.70	3.90	
	FFO/Interest	3.30	3.30	3.60	3.70	3.90	
	Debt to Capitalization	61.20	61.40	61.40	61.40	61.50	
Source: Utility Only Data and Calculations provided by EGDI							
Enbridge Inc.							
	EBIT/Interest Coverage	1.88	2.17	1.82	1.41	2.62	
	Debt/EBITDA	4.45	4.87	4.47	6.37	4.73	
	Adjusted Cash Flow Coverage Ratio	3.22	3.21	3.56	3.45	3.96	
	Debt to Capitalization	63.81	64.07	63.99	66.48	64.17	
Source SNL Interactive database							

c) SNL Financial reports its sources as follows:

SNL uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, SNL mines data from documents filed by the company, surveys, and other sources of public information.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister
D. Yaworski

VECC INTERROGATORY #3

INTERROGATORY

E- Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E3 Tab 1 Schedule 2 Page 1

a) Please provide the Latest Bond Rating Reports for EGD from S&P and DBRS.

RESPONSE

a) Please see the response to SEC Interrogatory # 7, filed at Exhibit I, Tab E2, Schedule 14.7 for the latest rating agency reports.

Witnesses: K. Culbert
M. Lister

VECC INTERROGATORY #4

INTERROGATORY

E- Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit M1 Tab 1 Schedule 2

a) Confirm that the Update includes the revised ROE calculation. If not provide a version with that change.

RESPONSE

a) Yes, the Company has updated the formula forecast ROE used in this impact statement to 9.03%.

Witnesses: K. Culbert
M. Lister

VECC INTERROGATORY #5

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit M1 Tab 1 Schedule 5

a) Please provide a schedule that shows the impact on the revenue deficiency of retaining the current deemed common Equity at 36% and if necessary adjusting other Components.

b) Please provide Explanatory Notes.

RESPONSE

a) and b) Please see the response to Energy Probe Interrogatory #3 found at Exhibit I, Issue E2, Schedule 7.3.

Witnesses: K. Culbert
M. Lister

CME, CCC, SEC, VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 1, Schedule 1 Updated, Testimony of R Fischer et al

Return on Equity, pages 1 to 3

a) Please provide a table showing EGDI's allowed ROE, actual ROE on a weather adjusted basis, actual unadjusted ROE, and actual unadjusted ROE before sharing since 1990, that is, prior to the 1993 and 2006 business risk assessments.

b) Please provide for each year since 1997 and the use of a formula ROE, the ROE broken out into the risk free rate component and the earned risk premium component (residual).

c) For each year since 1997 please provide a table with the average amount of common equity used for rate making purposes, and the amount of net income with the net income broken out into the risk free rate and risk premium component as identified in b) above.

RESPONSE

a) Please see the table provided on the following page:

Witnesses: K. Culbert
R. Fischer
M. Lister
S. Murray

Fiscal Year		Allowed ROE %	Normalized Actual ROE Before Sharing %	Actual ROE Before Sharing %	Normalized Actual ROE After Sharing %	Actual ROE After Sharing %
1990		13.250%	13.600%	13.570%	(a)	(a)
1991		13.125%	13.290%	9.400%	"	"
1992		13.125%	13.400%	13.290%	"	"
1993		12.300%	14.430%	15.260%	"	"
1994		11.600%	12.490%	14.690%	"	"
1995		11.650%	12.660%	10.710%	"	"
1996		11.875%	13.140%	15.000%	"	"
1997		11.500%	13.000%	13.170%	"	"
1998		10.300%	11.970%	8.310%	"	"
1999		9.510%	10.771%	7.943%	"	"
2000		9.730%	10.829%	8.229%	"	"
2001		9.540%	10.029%	10.800%	"	"
2002		9.660%	11.805%	8.982%	"	"
2003		9.690%	9.743%	13.140%	"	"
2004		9.690%	10.828%	12.342%	10.660%	12.165%
2005		9.570%	10.343%	10.343%	(a)	(a)
2006		8.740%	10.343%	7.200%	"	"
2007		8.390%	10.722%	11.639%	"	"
2008		8.660%	10.208%	11.867%	9.936%	11.586%
2009		8.310%	11.203%	12.361%	10.261%	11.422%
2010		8.370%	11.103%	10.248%	10.241%	9.386%
2011	(b)	7.940%	10.378%	10.433%	9.661%	9.719%

Note : (a) There were no earnings sharing amounts in these years, so ROE results are the same as in the previous columns.

(b) 2011 results are pending Board approval in EB-2012-0055.

b) The information requested is provided in tabular form on the following page. This information can also be seen graphically in response to CME, CCC, SEC, VECC Interrogatory # 2, filed at Exhibit I, Tab E2, Schedule 21.2, part b).

Witnesses: K. Culbert
R. Fischer
M. Lister
S. Murray

Fiscal Year	Board Approved ROE	Long Bond Forecast Embedded in ROE Formula Result	Implied Risk Premium in ROE Formula Result
	%	%	%
1998	10.30%	6.78%	3.52%
1999	9.51%	5.73%	3.78%
2000	9.73%	6.02%	3.71%
2001	9.54%	5.77%	3.77%
2002	9.66%	5.93%	3.73%
2003	9.69%	5.97%	3.72%
2004	9.69%	5.97%	3.72%
2005	9.57%	5.81%	3.76%
2006	8.74%	4.70%	4.04%
2007	8.39%	4.24%	4.15%
2008	8.66%	4.61%	4.05%
2009	8.31%	4.14%	4.17%
2010	8.37%	4.23%	4.14%
2011	7.94%	3.65%	4.29%

c) EGD does not feel that a response to this part of the interrogatory would be helpful to the Board, as it appears to imply that some portion of the Company's earnings could be labeled as 'risk-free'. EGD feels it is inappropriate to suggest that part of the company's net income can be labeled 'risk-free' or 'risk-premium' net income. A risk premium model is used to estimate or to proxy a fair return on equity for a regulated entity (ex. ante) because there is no way of directly observing what a fair return should be. Notionally labeling part of the net income as risk-free would be akin to suggesting that the Company could simply take its capital and earn a risk free rate of return. The risk for a gas distribution business relates to operations, safety, reliability, cost variability, regulatory risk, weather, interest rates, demand, supply, etc. There is no aspect of the business that is 'risk-free'.

Witnesses: K. Culbert
R. Fischer
M. Lister
S. Murray

CME, CCC, SEC, VECC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 1, Schedule 2, Testimony of R. Fischer et al

Capital Structure: Equity Ratio at pages 1 and 2

a) What is the purpose of graphing the common equity ratio against the allowed ROE over different points in time?

b) Please provide an equivalent graph to that on page 1 except graphing the allowed risk premium against the common equity ratio.

c) Does EGDI consider US utilities to be peers of EGDI in the sense that comparisons can be made without any adjustments?

d) Does EGDI accept that there are capital market differences between the US and Canada as reflected in Concentric's 0.74% adjustment for different long term (30 year) government bond rates?

e) Please confirm that DBRS has an A stable rating for EGDI and indicate when DBRS last rated EGDI as BBB+ or lower.

f) Please confirm that:

  (i) EGDI's S&P rating is a flow through of its parent Enbridge Inc.,

  (ii) The concern expressed by S&P is that EI's business risk has increased due to the competitive toll settlement (CTS) on the Enbridge System, and not that there has been a change in EGDI's risk.

g) Please confirm that if EGDI's debt cost increases due to an S&P downgrade flowing from the CTS on the Enbridge System that EGDI will *not* ask for those higher debt costs to be passed on to EGDI's Ontario ratepayers.

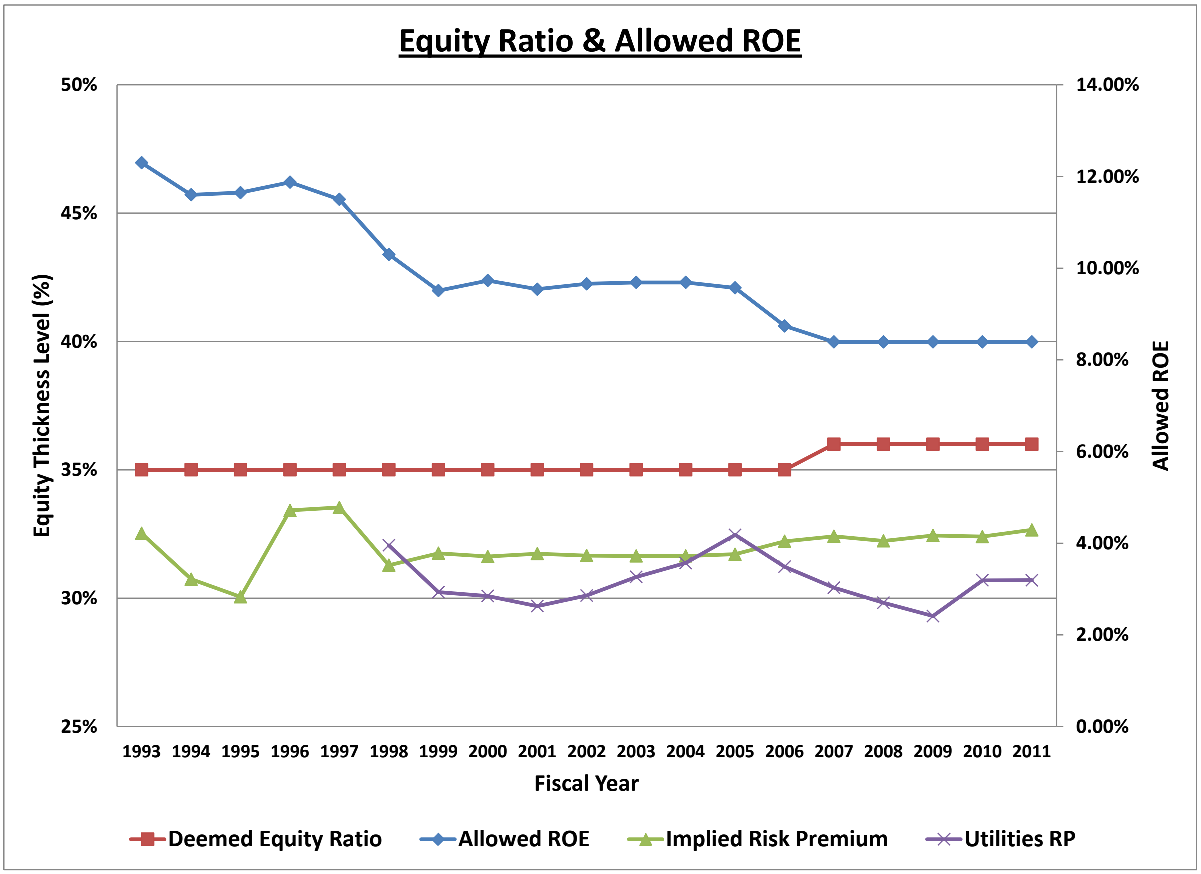
RESPONSE

a) The purpose of the graph is to show that while the Allowed ROE rate has plummeted over the 19 year period 1993-2011, the common equity ratio has remained relatively flat. If the Fair Return Standard holds, then this would suggest

Witnesses: R. Fischer
M. Lister
D. Yaworski

that EGD's business risk has declined since 1993. EGD believes that business risk on an absolute basis has increased since 1993, and that on a relative basis, is not less than, but in fact greater than the business risk faced by Ontario's electric utilities.

b) The requested graph is presented below.



With the decline in Long Canada Bond Yields, the Risk Premium measured as the 1997 Ontario Energy Board ROE formula to the Long Bond forecast resident in that formula has remained relatively flat. However, drawing conclusions only from the relationship between the Allowed ROE and Long Canada Bond Yields would be incorrect. As the Board indicated in its Report on the Cost of Capital,

Witnesses: R. Fischer
M. Lister
D. Yaworski

The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity.[1]

The graph also displays the Risk Premium is measured against average annual Canadian Utility debt yields, which show a decline in measured risk premium.

It is EGD's contention that business risk on an absolute basis has increased since 1993, and that on a relative basis, is not less than, but in fact greater than the business risk faced by Ontario's electric utilities, who have the same risk premium as the gas utilities, but a higher equity ratio.

c) EGD does believe that US utilities can be used for the purposes of cost of capital analyses. First, very little public data exists for Canadian utilities. Second, the business conditions and institutions that govern US utilities are very similar to those for Canadian utilities. The Ontario Energy Board and other regulatory authorities in Canada have accepted the use of US data for productivity studies, and the establishment of Cost of Equity (ROE) in the past. Therefore, EGD believes that a well-constructed analysis using US utility information is valid and appropriate.

Analysis implies that adjustments may be required under certain circumstances, depending on the quality and availability of data. EGD believes that Concentric Energy Advisor's analysis has been carefully and appropriately conducted.

d) EGD accepts that there may be differences in long term government bond rates between the US and Canada.

e) Confirmed. EGD's credit rating from DBRS is "A" Stable, and from S&P is "A-" Negative. It is not known if either DBRS or S&P has ever rated EGD with a "BBB+" or lower. DBRS downgraded EGD's rating in 2001 (from "A" high to "A") and S&P downgraded EGD's rating in 2002 (from "A" to "A-").

f)
  i. Not confirmed. As referenced in S&P's December 15, 2011 report on EGDI, they state "The corporate credit rating on Enbridge Gas is equivalent to our stand-alone evaluation of the company; at the current level, the ratings on ultimate parent, Enbridge Inc. (A-/Stable/--) do not constrain the credit ratings on EGD."

[1] Ontario Energy Board, EB-2009-0074, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. ii.

Witnesses: R. Fischer
M. Lister
D. Yaworski

ii. As expressed above, S&P's credit rating for EGDI is not constrained by Enbridge Inc.'s credit rating.

g) Not confirmed. If EGD's credit rating is downgraded, EGD will seek relief at the earliest possible opportunity. EGD believes it is a possibility that its credit rating could be downgraded for any variety of reasons. In its latest evaluation of EGD (May 2010) similar to Enbridge Inc., S&P noted that EGD's credit metrics are weak for its rating. EGD is making this application in part to minimize the risk of that possibility occurring.

Witnesses: R. Fischer
M. Lister
D. Yaworski

CME, CCC, SEC, VECC INTERROGATORY #3

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 1, Schedule 2, Testimony of R. Fischer et al

Business risk at pages 2 to 8

a) Will any of the EGDI's witnesses, R. Fischer, M. Lister and D. Yaworski be presented as expert witnesses with respect to business risk analysis?

b) Please provide copies of any rating or analyst reports that reflect the company's view on page 3 that the volumetric demand profile, system size and complexity, and environmental and technological advancements indicate an increase in the company's business risks since July 2007 when the Board determined EGDI's equity ratio to be 36%.

c) Please indicate whether the use of high efficiency gas furnaces and the resulting persistent reduction in the demand for gas has increased the forecasting error attached to EGDI's revenue requirement, and if so quantify its impact on ROE variability.

d) Please provide regulatory precedent for the proposition that increased size is a risk factor as claimed by EGDI.

e) Please advise whether EGDI is aware of prior Ontario Energy Board Decisions accepting that increased size is a risk *mitigating* factor.

f) Please provide a copy of the business risk testimony filed in support of EGDI's request for 38% common equity in 2006 and a brief synopsis of the major risk factors identified at that time and whether or not those risk factors remain relevant or have changed in a material way.

g) Please restate the 1993 capital expenditures of $247.5 million in 2012 dollars, that is, please adjust for the inflation between the two time periods (page 6).

h) Please provide a table showing the free cash flow, that is, cash flow from operations and capital expenditures (separately) for each year since 2000.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

i) Please indicate the difference in financing problems faced by free cash flow positive and free cash flow negative firms.

j) In previous business risk testimony, experts have provided cost comparisons of natural gas with alternative fuels. For 2006 (as filed at that time), as well as currently, please provide a cost comparison for industrial users, commercial users and residential users in the major rate classes on a consistent basis for all three users of natural gas against the major competitive fuels such as fuel oil and electricity.

k) Further to (i) above, please reproduce extracts from company securities filings (prospectuses etc.) for 2006, as well as currently, that discuss inter-fuel competition.

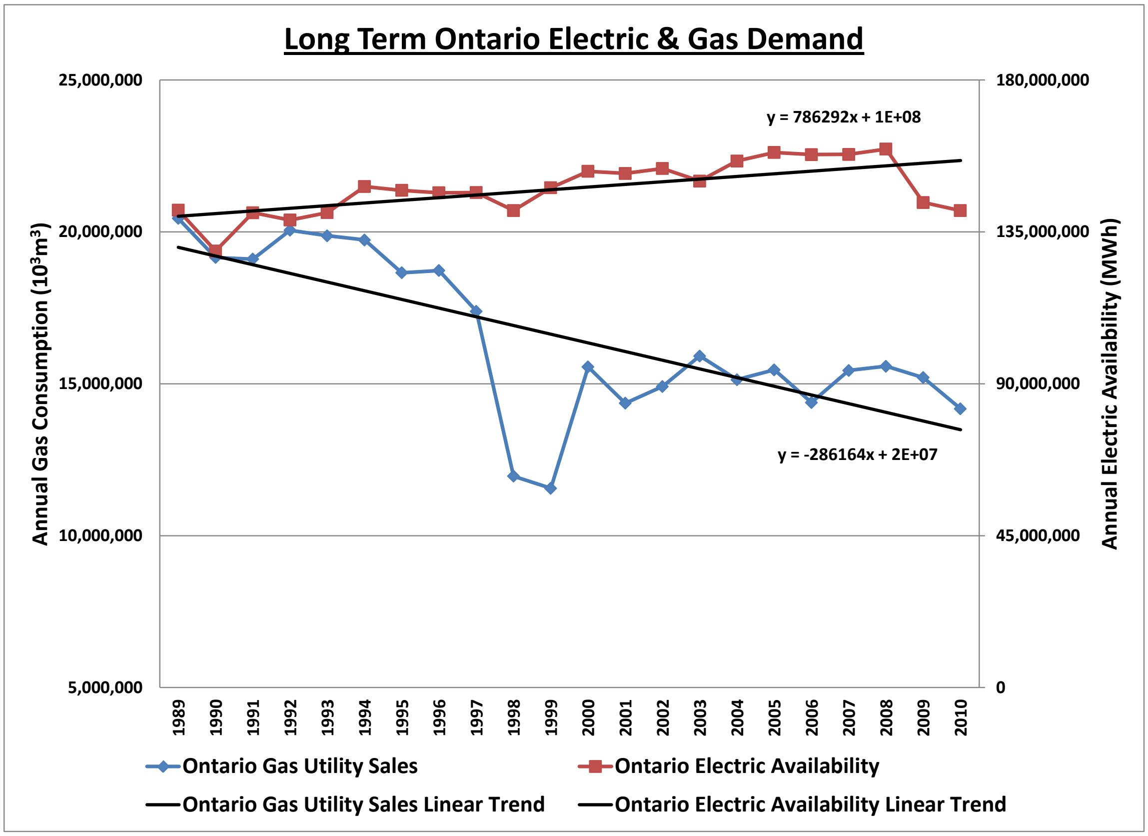
l) In previous business risk evidence, experts have always rated gas distributors partly on the basis of the composition of their demand. Please confirm that the company judges such comparison to still be useful and provide for 2006 and currently a revenue breakdown (minus gas costs) for industrial, commercial and residential users for EGDI, Union Gas, ATCO Gas, GMI and Fortis Energy BC (and predecessor companies such as BC Gas, TGI, Inland Gas etc.).

RESPONSE

a) Company witnesses will not be presented as 'expert' witnesses.

b) To be clear, EGD's position is not just that business risks have increased materially since 2007 when the Board determined EGD's equity ratio to be 36%. As stated in the evidence, the Company's position is that a 1% increase in the equity ratio since 1993 has not kept pace with the change in business risk since that time.

The attached S&P report entitled, "Industry Surveys: Natural Gas Distribution" presents a discussion of several factors that have increased business risks for natural gas utilities (see Attachment 1). The report highlights demand changes, influenced by both conservation and volatile prices as producing higher risks for the industry. The report also states, "The bottom line for the Natural Gas industry is that as overall energy demand continues to rise, consumption of other forms of energy is rising and filling the gap." As shown in the evidence at Exhibit E2, Tab 1, Schedule 2, p. 11 (reproduced on the following page), the long run growth in electricity in Ontario is clearly materially different from the long run reduction in gas consumption. The chart also shows that gas consumption has been considerably more volatile than electricity consumption.



Source: Statistic Canada, Energy Statistics Handbook, Tables 6.7, 8.4, 8.5, & 8.6

Insofar as system size and complexity are concerned, it is the Company's position that these have resulted in greater variability in operating and capital expenditure requirements. Variability in costs is directly relevant to business risk and was in fact a key reason for the recent downgrade of Enbridge Inc. (see CME, CCC, SEC, VECC Interrogatory response at Exhibit I, Tab E2, Schedule 21.2). Variability in costs is not expected to diminish in the future, and in all likelihood will increase as distribution assets continue to age.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

In addition to the increase in absolute business risk, EGD's position is that, on a relative basis, gas distribution is not less risky than electric distribution. In Ontario, that means that there is a contradiction in the deemed equity ratios of the electric distribution utilities, who operate with a 40% deemed equity ratio versus the gas distribution utilities, who operate with a 36% deemed equity ratio.

c) EGD's average use forecasting methodology has performed very well for the past decade or more. The change in the value of the vintage variable within the models the Company uses to estimate small volume (Rate 1 and Rate 6) average use has not materially improved or decreased in accuracy since the variable was first introduced.

d) It is not the Company's position that an increase in size has increased business risk. As explained in part b) to this response, increased size and system complexity result in higher cost variability, which is one of several reasons that the Company believes its business risk has increased since 1993, and by more than the 1% increase in equity ratio since that time would justify.

   As explained in the evidence produced by Concentric Energy Advisors, at Exhibit E2, Tab 2, Schedule 1, the Board's experience with size as a determinant of business risk is clear. Initially the equity ratios of the electric utilities' were determined on the basis of size, with larger firms considered low risk, and therefore generating a lower equity ratio. Then, in the Board's 2006 Report on Cost of Capital, the Board that size should not be a key determinant of risk.

e) Please see the response provided in part d) above.

f) A copy of the business risk testimony filed in support of EGD's request for 38% equity thickness in 2006 is attached (see Attachment 2). The major risk factors identified in the testimony include:
   - Volume risk – general service volumes have been steadily declining since at least 1995. The higher incidence of high efficiency heating stock is contributing to the declines in average uses, and means the trend will continue.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

- Natural gas price risk – commodity price levels have increased and become more volatile.
- Customer dynamics – a trend towards multiple housing units, away from traditional, single detached homes has been lowering the space heating requirement per customer.
- Regulatory & Legislative environment – the number of proceedings and the intensity of intervention cause great uncertainty in regulatory outcomes.

EGD believes that all of the risks outlined above continue to be prevalent, and have resulted in increased business risk since 1993.

g) In 1993, capital expenditure requirements to maintain the system were $247.5 million per year. Adjusting for inflation using actual, historical, calendar year GDPIPI FDD would result in a 2012 annual capital expenditure of $337.35 million. For 2013, EGD's capital budget is $483.9 million.

h) The table below shows EGD's free cash flow (cash flow from operations and capital expenditures) for each year since 2000:

($ Millions)	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual
Net income (after ESM)	104.4	108.0	122.9	105.8	120.5	127.8
Depreciation and amortization	159.3	152.9	159.5	167.7	177.2	195.9
Changes in Allowance for Working Capital	(63.8)	(291.7)	197.1	(29.8)	(40.6)	(184.2)
Cash Flow from Operations	199.9	(30.8)	479.5	243.7	257.1	139.5
Capital Expenditure	215.2	249.8	252.9	224.8	278.4	315.5
Free Cash Flow	(15.3)	(280.6)	226.6	18.9	(21.3)	(176.0)

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

($ Millions)	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual
Net income (after ESM)	130.1	140.1	134.9	140.4	140.3	138.5
Depreciation and amortization	210.1	228.4	237.0	251.3	267.2	276.9
Changes in Allowance for Working Capital	69.8	145.8	(67.6)	126.2	117.2	(25.1)
Cash Flow from Operations	410.0	514.3	304.3	517.9	524.7	390.3
Capital Expenditure	364.6	354.9	366.0	349.1	337.6	399.2
Free Cash Flow	45.4	159.4	(61.7)	168.8	187.1	(8.9)

i) Firms generating positive free cash flow can readily demonstrate the ability to service financing obligations; whereas, firms with negative free cash flow cannot. As a result, investors will likely perceive the firm with negative free cash flow as being more risky. The perceived risks could be mitigated by: the commercial construct under which the firm operates (for example: regulatory protection, cost-of-service tolling methodology, contract terms, etc.), the driver of negative free cash flow (for example: capital expansion versus operational weakness) and the duration of negative cash flow. Regardless of the mitigants, on average, a firm generating positive free cash flow would likely have deeper and broader access to financing than would a firm with negative free cash flow.

j) The table on the following page displays relative cost comparisons between delivered natural gas, fuel oil, and electricity for each of the three classes of consumption: residential, commercial, and industrial.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

Annual Burner-Tip Cost Comparisons: Natural Gas vs Alternate Fuels		
Rates in (¢/m3)	**2006**	**2011**
Residential		
Natural Gas - Rate 1	52.84	32.72
Residential Electricity	85.91	94.99
Home Heating Oil	74.89	105.02
Commercial		
Natural Gas - Rate 6	47.87	27.46
Commercial Electricity	64.54	84.36
Light Fuel Oil	57.73	80.41
Industrial		
Natural Gas - Rate 110	41.46	19.41
Industrial Electricity	56.63	76.56
Light Fuel Oil	57.73	80.41
Heavy Fuel Oil	33.06	57.74

Notes:

- Natural gas rates are based on EGD's OEB-approved rates.
- Electricity rates are based on Toronto Hydro's OEB-approved rates and do not include the Ontario Clean Energy Benefit.
- Oil prices are based on Statistics Canada historical rates.
- Costs have been calculated for the efficiency-adjusted energy equivalent consumed by a typical residential customer on Rate 1, a typical commercial customer on Rate 6, and a typical industrial customer on Rate 110, and include all service, delivery, and energy charges. HST is not included.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

k) The Annual Information Form for the Year Ended December 31, 2011 states the following:

Price Advantage of Natural Gas
Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue. During 2011, natural gas in the residential market experienced, on average, a price advantage on an equivalent annual volume basis of 66% (2010 - 60%) against electricity and 69% (2010 - 58%) against domestic fuel oil.

The Annual Information Form for the Year Ended December 31, 2006 states the following:

Price Advantage of Natural Gas
Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue. During 2006, natural gas in the residential market experienced, on average, a price advantage on an equivalent annual volume basis of 38% (2005 – 40%) against electricity and 30% (2005 – 32%) against domestic fuel oil.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

l) EGD does not have access to the information requested. The Company is able to produce the following equity ratio information:

	Approved Equity Ratios	
	2006	**2012**
EGD	35.0%	36.0%
Union Gas	35.0%	36.0%
ATCO Gas	38.0%	39.0%
GMI	38.5%	38.5%
Fortis Energy (Terasen Gas)	35.0%	40.0%

EGD and Union have both requested an increase to the equity ratio from the Board for Test Year 2013. ATCO Gas's equity ratio was increased from 37.0% to 38.0% in 2005. Fortis Energy's equity ratio was increased from 35.0% to 40.0% in 2010.

Witnesses: K. Culbert
R. Fischer
R. Lei
M. Lister
D. Yaworski

STANDARD & POOR'S

Industry Surveys
Natural Gas Distribution

Christopher B. Muir, Gas Utilities Analyst

January 14, 2010

This issue updates the one dated July 16, 2009.
The next update of this Survey is scheduled for July 2010.

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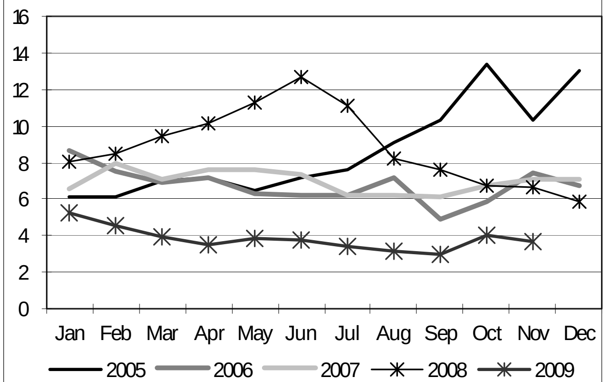
CURRENT ENVIRONMENT

Natural gas prices fall in 2009

Reaching a recent low of $1.64 per million British thermal units (MMBtu, Henry Hub spot price) on September 4, 2009, natural gas prices had declined precipitously from a peak of $13.41 on July 2, 2008. Prior to the July peak, prices had risen quickly from a pre-spike low of $5.20 per MMBtu. Prices have been very volatile since the September 2009 low, reaching $3.695 per MMBtu on September 25, falling to $2.23 on October 2, rising to $5.06 on October 22, falling to $2.30 on November 13, and then rising to $4.51 on December 1. In the first nine months of 2009, Henry Hub average bid-week prices (a blend of spot and contract prices in the last week of every month, which is when the largest volume of trading occurs) averaged 60% lower than in the comparable 2008 period. In 2009's fourth quarter, average bid-week prices are expected to be 53% lower than they were in 2008. In 2010, however, S&P expects prices to be 7.7% higher than in 2009.

HENRY HUB NATURAL GAS PRICE
(Dollars per million Btu, first trading day of month)



Btu-British thermal units.
Source: US Energy Information Administration.

Natural gas prices have been very volatile throughout the decade, with four separate spikes over $10 per MMBtu. The first such spike barely brushed past the $10 mark, peaking at $10.52 on December 29, 2000, due to cold weather. The next spike, to $22.00, occurred on February 25, 2003, also due to cold weather. On September 22, 2005, prices jumped to $16.00, followed by a second lower spike in December, related to production cuts caused by Hurricane Katrina. Prices rose throughout late 2007 and early 2008, reaching a peak of $13.41 on July 2, 2008, which we think was due in part to large speculative positions taken by relatively short-term traders. We believe that continued volatility is likely and that price spikes will continue to be relatively frequent.

Spot prices are currently below the 10-year bid-week average of $5.83 per MMBtu. Annual average wellhead prices in 2009 are down as well: prices in 2007 were $6.46 per MMBtu and averaged a record $8.07 per MMBtu in 2008, but declined to an average of $3.65 per MMBtu in the first nine months of 2009, with September 2009 averaging just $2.92 per MMBtu. Henry Hub spot prices peaked on December 13, 2005, helping to raise the annual average wellhead price for 2005 to what was then an all-time high of $7.41 per MMBtu. In 2006, the annual average wellhead price declined to $6.47 per MMBtu—lower than in 2005, but still substantially above the pre-Katrina 10-year average annual price of $3.15 per MMBtu.

Barring any weather-driven catastrophe or a dramatic decline in inventories, we believe that average prices will remain below the 10-year average in 2010 and 2011, with some volatility, but less than that seen in 2008. As of November 16, 2009, using forecasts from Global Insight, an economic research firm, Standard & Poor's projection for Henry Hub bid-week price was $3.77 per MMBtu in 2009, $4.06 in 2010, and $5.23 in 2011.

Currency issues also have an effect on natural gas prices in the US. For example, should the value of the US dollar weaken against the Canadian dollar, the costs of Canadian natural gas could rise, which would put upward pressure on prices. This could make more expensive production regions become more attractive, thus allowing additional supplies to enter the market and potentially limiting how high prices could reach. Conversely, a significant strengthening of the US dollar against major worldwide currencies could make the US more attractive for cargoes of liquefied natural gas (LNG), which would put downward pressure on prices due to increasing supply. LNG shipments to the US were down sharply in late 2007, 2008, and early

2009, as shipments headed to other countries where prices were higher. However, there was a muted recovery in LNG cargoes entering the US in early 2009, coinciding with a strengthening of the dollar, despite falling US natural gas prices.

WINTER HEATING SEASON NORMAL IN 2008–09

According to data from the National Weather Service's Climate Prediction Center (CPC), the US winter heating season (November through March; generally, the time of peak demand for natural gas) was marked by normal weather in the winter of 2008–09. Using the population-weighted gas home heating data, US heating degree days were 0.1% higher than normal in the 2008–09 season, 1.1% lower than normal in the 2007–08 season, 7.8% below normal in the 2006–07 season, and 10.2% below normal in the 2005–06 season. US heating degree days totaled 3,910 in the 2008–09 season (up 1.2% from the leap year–adjusted previous season), 3,863 (up 6.6%) in the leap year–adjusted 2007–08 season, 3,624 (up 2.3%) in the 2006–07 season, and 3,543 (down 4.5%) in the 2005–06 season. (One heating degree day is counted for every degree by which the daily average temperature falls below 65 degrees Fahrenheit.)

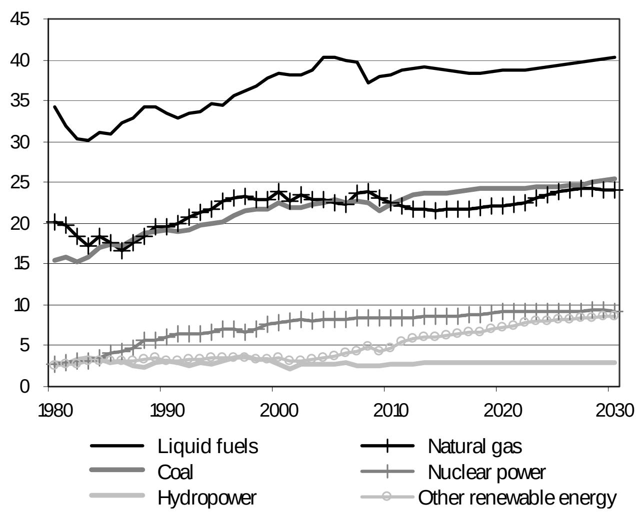
There were 11 fewer heating degree days in the first quarter of 2009 (2,424 total), according to the CPC, after February and March recorded 90 fewer heating degree days than the same months a year earlier. The impact of the near-normal first quarter is likely to combine with the projected 5.4% drop in full-year 2009 in end-use consumption (due to the weak economy) to put downward pressure on distribution company revenues. At many distribution companies, however, rate increases and some customer growth could mitigate the total impact.

In the current 2009–10 heating season, early data show that there were only 438 heating degree days through November 28, 19% warmer than normal and 18% warmer than the year-earlier period. This is a weak start, but on a volume-weighted basis, only 14% of a normal heating season had occurred.

Lower consumption seen in 2009 and 2010

In November 2009, the Energy Information Administration (EIA), a statistical agency within the US Department of Energy, projected that natural gas consumption would fall by 1.9% for full-year 2009 and by 1.1% in 2010.

PROJECTED US ENERGY DEMAND
(Quadrillion Btu)

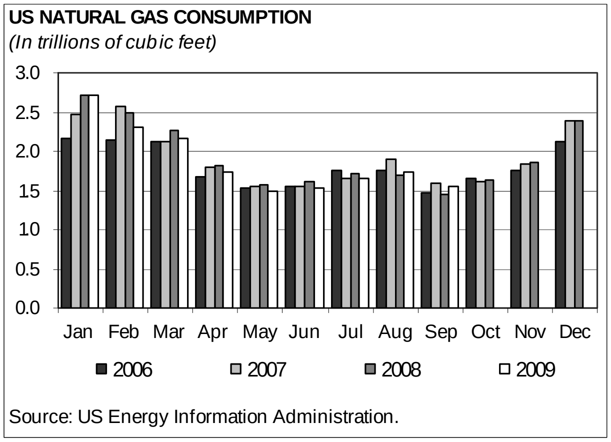


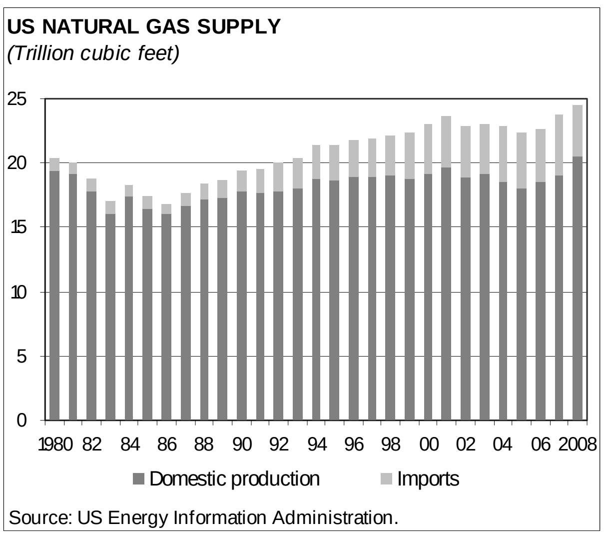
Btu-British thermal units.
Source: US Energy Information Administration.

The projected 2009 and 2010 consumption declines are markedly lower than the 1.6% 50-year compound annual growth rate in consumption, the 1.3% 25-year growth rate, and the 0.4% 10-year growth rate. EIA said that weakness in consumption in 2009 would be driven by weak economic conditions and slight declines in usage, partly offset by a 2% increase in usage for electric generators (those that use natural gas to fuel electricity generating equipment) spurred by lower natural gas prices. For 2010, the EIA said that it expects reduced consumption by power generators to more than offset residential, commercial, and industrial consumption growth as new coal-fired generating capacity and higher gas prices reverse appetite for gas.

Year to date through September 2009, total natural gas consumption fell by 2.6% over the same period in 2008, driven by a 10.5% decrease in industrial consumption, a 2.4% drop in residential consumption, and a 1.3% drop in commercial consumption. Given the EIA's projection of only a 1.9% decline in gas consumption for full-year 2009, these data suggest that the EIA expects consumption for the remainder of 2009 will roughly match consumption for the fourth quarter of 2008.

Growth in residential consumption of natural gas has been markedly slower over the past 50 and 25 years, with compound annual growth rates of 1.2% and 0.4%, respectively, according to the EIA. However, the 10-year average annual growth rate of 0.7% is higher than that of total consumption, due mostly to weakness in industrial and to a lesser extent commercial consumption during the same period. Because the residential market provides most of the profit for natural gas distributors, ongoing slow growth in consumption and conservation efforts due to historically high prices is likely to continue to pressure earnings growth for distributors that do not have revenue decoupling rate orders in place.





Natural gas usage by electric power generators has grown by 3.8% annually for the past 10 years, more than offsetting a 2.3% average annual decline for industrial users. Average annual commercial demand growth for the past 10 years was 0.4%. Residential, commercial, industrial, power generation, and other usage accounted for 23%, 15%, 31%, 31%, and less than 0.1% of total natural gas delivered in 2008.

From a policy perspective, some energy industry participants question the wisdom of burning natural gas for electric power generation: efficiency rates range from 30% to 60%, depending on the type of power plant. Steam generation and gas turbines have ranges in the low end, while combined cycle plants have ranges near the high end. In contrast, modern home furnaces can achieve efficiencies of up to 96%, water heaters up to 86%, and clothes dryers up to 80%. As a result, these people ask whether limited natural gas resources should be squandered on generating electricity when other inexpensive methods of generating power exist.

The bottom line for the natural gas industry is that, as overall energy demand continues to rise, consumption of other forms of energy is rising and filling the gap. In the late 1990s, many forecasters had predicted strong increases in natural gas demand—with total usage going up to 25 trillion cubic feet (Tcf) to 30 Tcf per year, for example—but to date, such growth has not materialized.

The EIA now expects gas demand to remain almost unchanged, rising from 23.0 Tcf in 2008 to 23.5 Tcf in 2030. The EIA forecasts that commercial demand will rise 9.5% to 3.43 Tcf and electric power consumption will rise by 4.7% to 6.70 Tcf by 2030. It expects these increases will be partly offset by a 4.6% fall in industrial demand to 6.34 Tcf in 2030 and a 1.0% decline in residential consumption to 4.87 Tcf. These forecasts are sharply lower than forecasts made in early 2008.

Weak economy curbs demand

Weather is only one variable affecting natural gas consumption patterns; price and the strength of the economy are also important. The relatively high prices of the last few years—a period that saw the advent of oil priced higher than $100 per barrel and natural gas prices above $10 per MMBtu—have hurt demand by encouraging industrial users, which have the option, to switch between natural gas and other fuels. As demand has weakened or remained flat, many companies have continued to struggle to retain profitability.

However, despite the recent drop in natural gas prices, industrial usage in the first three quarters of 2009 was 10.5% and 9.1% below such usage in the first three quarters of 2008 and 2007, respectively. While high prices may have affected industrial usage earlier in 2008, the recession has taken its toll in the latter part of 2008 and in 2009. In 2008, total consumption rose at just 0.6%. We believe that industrial consumption will recover in pace with the overall economy.

In the longer term, several supply-side factors—including increasing production, rising imports of liquefied natural gas (LNG), and more pipeline capacity—may put downward pressure on prices, thus leading to increased industrial use. (See the "Industry Trends" section of this *Survey* for more details on these issues.) Some of these factors may also generate increased demand for gas if they improve the reliability of supply and eliminate periodic shortages on the distribution end.

US PRODUCTION INCREASING?

In 2008, total dry natural gas production increased 6.7%, following a 3.2% increase in 2007 and a 2.5% rise in 2006, according to the EIA. [Dry natural gas is defined as the natural gas that remains after liquefiable hydrocarbons (propane, butane, etc.) and sufficient contaminant gases (carbon dioxide, hydrogen sulfide, etc.) have been removed.] The EIA also measures natural gas "gross withdrawals," a figure that includes gas produced from gas and oil wells before various processing steps (including repressuring and the removal of non-hydrocarbon gas) take place. The total dry natural gas production figure is calculated after the extraction loss is deducted from the marketed production figure.

Dry gas production totaled 20.4 Tcf in 2008, slightly below the record production levels of the early 1970s, when annual production routinely exceeded 21.0 Tcf. In fact, 2008 was the first time since 1974 that dry gas production exceeded 20 Tcf; it was also the highest level since a more recent peak of 19.6 Tcf in 2001. If current production levels were maintained, production in 2009 would exceed 2008 levels.

The year started out strongly. Year to date through September 2009, dry gas production rose 3.8% over the comparable year-earlier period. In March 2009, the EIA projected in its *Annual Energy Outlook 2010* that total dry natural gas production would increase 0.6% in 2009, then fall 2.9% in 2010. However, in its November 10, 2009, *Short-Term Energy Outlook*, the EIA updated its forecast, stating that it expects natural gas production to rise 2.8% in 2009. EIA sees production decreasing 3.8% in 2010, hurt by falling rig counts and projected steeper decline rates from wells that entered service in 2009.

US weekly average rig counts increased steadily from 830 in 2002 to 1,879 in 2008, according to data from Baker Hughes, an oil and gas industry consulting business. Five-year average rig counts also increased by an average of 680 rigs over the same period. Keeping that in mind, US rig counts were 54.2% above the five-year average in December 2006. From that point until November 2008, the premium to the five-year average for US rig counts slowly dropped, despite continued rises in the actual number of rigs. In November 2008, the actual number of rigs began to decline, sending comparisons to the five-year average deep into negative territory. By June 12, 2009, comparisons had dropped to 44.4% below the average, with the number of rigs falling by 54% from the same period in 2008. Since June, rig counts have recovered somewhat with the rise in natural gas prices to 29.9% below the five-year average and 39% below year-ago levels.

North American rig counts, according to data gathered from Baker Hughes, started to trend back toward their five-year average, having averaged 26.5% above the average since the beginning of 2008 and reaching 34.2% above the average on September 19, 2008. By December 26, 2008, (the last week reported in 2008) North American rig counts were only 10.8% above the five-year average. North American rig counts continued to plummet through most of 2009, falling to 54% of prior year levels or 47.7% below the five-year average on July 17. Since November 27, rig counts have partially rebounded to levels 36% below the same week in 2008, or 30.4% below the five-year average.

Increasing rig productivity may account for the relatively steady production despite a falloff in rig counts. According to a report from Platts (which, like Standard & Poor's, is a unit of The McGraw-Hill Companies), the average number of wells per rig increased to 1.5 in early 2009, from 1.0 in 2005. Using horizontal and directional drilling techniques, operators are now able to drill several wells per rig. The EIA attributes the continued strong production in 2009 to new supplies from unconventional gas fields, such as shale plays, and a return of some Gulf of Mexico production that was shut in due to damage from Hurricanes Gustav and Ike.

LNG imports rebounding slightly

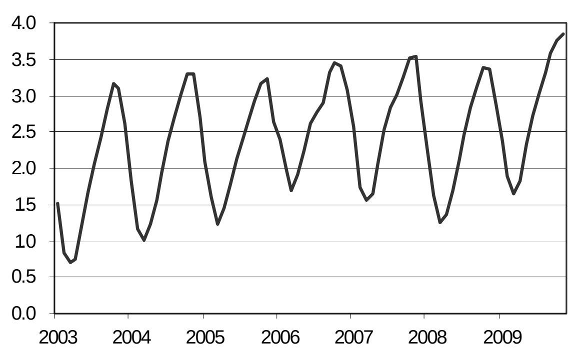
One element that has been added to the mix of the natural gas distribution business recently is the amount of LNG being imported into the US. In 2008, imports of LNG averaged 0.96 billion cubic feet per day (Bcf/d), the lowest level since 2002 and down 54% from 2007.

In 2009, however, the EIA expects LNG imports to rise to 1.29 Bcf/d. Reasons for the projected increase include the start-up of new liquefaction capacity in Qatar and Yemen. Despite the increasing demand abroad for LNG during the winter months, the EIA believes that the new liquefaction capacity was likely to lead to increasing shipments to the US through the end of the year. Through September 2009, LNG shipments arrived at a 1.29 Bcf/d pace, compared with 0.99 Bcf/d for the same period a year earlier. In 2010, the EIA expects LNG imports to continue its rebound to 1.81 Bcf/d for reasons similar to those fueling the projected 2009 increase. (For more details about new LNG facilities, see the "Industry Trends" section of this *Survey*.)

Inventories reach record levels

The amount of working gas in storage in the lower 48 states totaled a record 3,837 Bcf as of November 27, 2009, according to EIA estimates. Stocks were 479 Bcf (14.3%) higher than a year earlier, and were 556 Bcf (16.9%) higher than the five-year average. The EIA is forecasting March end-of-winter inventories of 1,739 Bcf, the highest since 1991. This forecast assumes that winter withdraws are 14% higher than the five-year average, which seems questionable to us given the early warm weather. In fact, the withdraw season typically begins in early November, but storage facilities added gas for each of the three weeks since the start of the normal withdraw season. Assuming that base gas in storage remains unchanged from the end of September, we estimate that the amount of gas in storage (base and working) is a record 95.4% of total storage capacity. While new storage facilities continue to be built, we wonder if slowing production will be enough to offset projected lower 2010 summer gas usage by electric generators to meaningfully reduce the capacity utilization by 2010's peak storage.

SEASONAL VARIATIONS IN WORKING NATURAL GAS UNDERGROUND STORAGE VOLUMES
(Trillion cubic feet)



Source: US Energy Information Administration.

AVERAGE NUMBER OF RATE CASES LIKELY

Year to date through December 3, 2009, 27 rate cases had been completed, according to Regulatory Research Associates (RRA), a regulatory consulting firm that is a division of SNL Financial. Recently, there were another 38 rate cases filed, 10 of which were likely to be completed by the end of 2009, according to RRA. The five-year average for rate cases completed is 35 per year.

The average requested return on equity (ROE) for pending rate cases is 11.18%, with an average requested equity to total capitalization (equity component) of 49.3% and an average requested return on rate base (RORB) of 8.70%. For rate cases completed since 2003, the average ROE granted was 10.5% versus a requested ROE of 11.6%; the average RORB granted was 8.39% versus a requested return of 9.04%. In observable cases, granted rate base was $1.17 billion (or 1.52%) less than rate base requested for the period.

During 2009, completed rate cases had an ROE of 10.13%, an RORB of 8.05%, and an equity component of 47.7%, versus requested amounts of 11.57%, 8.92%, and 50.26%, respectively. For cases through December 3, 2009, the granted rate base was $426 million (or 5.9%) lower than requested, though $273 million of the shortfall was from two companies, Northern Illinois Gas Co ($179 million) and Hope Gas Inc. ($94 million). In 2008, observable granted rate base was $171 million (or 0.92%) less than rate base requested. (See the "How the Industry Operates" section of this *Survey* for further discussion of rate-setting mechanisms.)

One notable rate case was filed on April 29, 2008, by Northern Illinois Gas Co. (NIGC), a subsidiary of NICOR. In that case, NIGC filed for a 25% revenue increase, or $140 million. Even with the requested increase, the company would still have been one of the lowest-cost distributors of gas in its state. The company sought a 9.27% RORB and an 11.15% ROE, with a 56.8% equity component. Regulators authorized an increase of just half the requested amount on March 25, 2009, but upon appeal, the rate hike was increased to $80.2 million. The approved ratios were an 8.09% RORB and a 10.17% ROE, with a 51.1% equity component.

PENDING RATE CASES
(As of November 2009)

STATE	COMPANY	FILING DATE	RATE INCREASE (MIL.$)	RETURN ON RATE BASE (%)	RETURN ON EQUITY (%)	COMMON EQUITY TO TOTAL CAP. (%)	RATE BASE (MIL.$)	ACTION LIKELY BY
Arizona	UNS Gas Inc.	11/7/2008	9.5	8.75	11.00	50.0	182.3	NA
California	Pacific Gas and Electric Co.	NA	226.0	8.79	11.35	52.0	NA	NA
Illinois	North Shore Gas Co.	2/13/2009	20.0	9.06	11.87	56.0	178.9	1/13/2010
Illinois	Peoples Gas Light & Coke Co.	2/13/2009	122.4	9.27	11.87	56.0	1,298.7	1/13/2010
Illinois	Central Illinois Light Co.	6/5/2009	8.8	9.15	11.60	43.6	228.8	5/1/2010
Illinois	Central Illinois Public	6/5/2009	11.4	8.48	11.25	48.7	219.9	5/1/2010
Illinois	Illinois Power Co.	6/5/2009	24.9	9.55	11.60	44.1	572.3	5/1/2010
Illinois	MidAmerican Energy Co.	6/2/2009	3.4	8.83	11.25	47.8	37.4	5/31/2010
Kentucky	Duke Energy Kentucky Inc.	7/1/2009	17.5	7.67	11.00	49.9	253.8	5/1/2010
Kentucky	Atmos Energy Corp.	10/29/2009	9.5	9.00	11.00	51.4	184.7	8/29/2010
Michigan	Consumers Energy Co.	5/22/2009	114.4	7.28	11.00	41.1	2,904.9	5/22/2010
Michigan	Michigan Consolidated Gas Co.	6/9/2009	192.6	7.32	11.25	38.9	2,359.0	6/9/2010
Michigan	Michigan Gas Utilities Corp	7/1/2009	8.4	7.79	12.00	47.3	189.9	7/1/2010
Minnesota	CenterPoint Energy Resources	11/3/2008	59.8	8.29	11.00	50.5	692.0	12/31/2009
Minnesota	Northern States Power Co.	11/12/2009	16.2	8.80	11.00	52.5	440.6	9/12/2010
Mississippi	CenterPoint Energy Resources	7/20/2009	6.2	8.95	11.25	55.6	69.3	11/30/2009
Missouri	Southern Union Co.	4/2/2009	32.4	8.43	11.25	48.0	605.0	2/28/2010
Missouri	Empire District Gas Co.	6/5/2009	2.9	8.98	11.30	46.4	57.7	5/1/2010
Montana	NorthWestern Energy Division	10/16/2009	2.0	8.30	10.90	49.5	256.6	7/16/2010
Nebraska	SourceGas Distribution LLC	7/2/2009	9.3	9.05	12.10	50.0	92.2	2/23/2010
Nebraska	Black Hills Nebraska Gas	12/2/2009	12.1	NA	NA	NA	NA	9/1/2010
New Jersey	Pivotal Utility Holdings Inc.	3/10/2009	24.8	8.57	11.25	50.4	448.4	11/15/2009
New Jersey	Public Service Electric Gas	5/29/2009	96.9	8.86	11.50	51.2	2,317.1	3/1/2010
New York	NY State Electric & Gas Corp.	9/17/2009	63.4	8.62	11.43	48.0	522.0	8/15/2010
New York	Rochester Gas & Electric Corp.	9/17/2009	62.9	9.46	11.43	48.0	409.5	8/15/2010
New York	Consolidated Edison Co.	11/6/2009	160.8	8.13	10.80	48.2	3,093.3	9/30/2010
New York	Central Hudson Gas & Electric	7/31/2009	4.0	7.58	10.00	48.0	190.0	NA
Oklahoma	ONEOK Inc.	6/26/2009	66.1	8.81	11.00	55.3	764.2	12/31/2009
Tennessee	Chattanooga Gas Company	11/16/2009	2.6	8.28	11.00	50.9	97.8	NA
Texas	Atmos Energy Corp.	4/24/2009	7.7	9.14	11.50	48.9	1,288.0	11/30/2009
Texas	CenterPoint Energy Resources	7/31/2009	25.4	9.07	11.25	55.6	417.3	3/31/2010
Washington	Avista Corp.	1/23/2009	4.9	8.68	11.00	47.5	178.3	12/1/2009
Washington	Puget Sound Energy Inc.	5/8/2009	29.5	8.50	10.80	48.0	1,474.0	4/1/2010
West Virginia	Mountaineer Gas Company	6/1/2009	21.0	7.89	10.89	35.0	210.9	3/29/2010
Wisconsin	Madison Gas and Electric Co.	4/29/2009	4.4	9.18	10.80	56.1	130.2	12/31/2009
Wisconsin	Wisconsin Electric Power Co.	3/13/2009	22.1	9.45	10.75	53.0	412.9	12/31/2009
Wisconsin	Wisconsin Gas LLC	3/13/2009	38.9	10.20	10.75	46.7	611.4	12/31/2009
Wisconsin	Wisconsin Power and Light Co	5/8/2009	6.2	9.71	10.60	53.5	212.2	12/31/2009

NA-Not available.
Source: Regulatory Research Associates.

Notable pending rate cases include a $226 million rate case filed by Pacific Gas and Electric Co., a $193 million case filed by Michigan Consolidated Gas, a $161 million case filed by Consolidated Edison Co. of New York, a $122 million case filed by Peoples Gas Light & Coke Co., and a $114 million case filed by Consumers Energy Co. The Peoples Gas Light & Coke, Consumers Energy Co., and Michigan Consolidated Gas cases are expected to be decided in the first half of 2010, and the Consolidated Edison Co. of New York case in the second half, while RRA has not estimated the date for Pacific Gas and Electric Co.'s case.

CAP & TRADE: A POTENTIAL DETRIMENT FOR NATURAL GAS?

According to the US Environmental Protection Agency (EPA), "Cap and trade is an environmental policy tool that delivers results with a mandatory cap on emissions while providing sources flexibility in how they comply." A cap and trade system sets a limit on total emissions allowed and then provides allowances to each emissions source that they can trade based on their need or excess. As emissions are produced, an emissions source surrenders the allowances equal to its emissions. Because coal plants produce large quantities of carbon dioxide, a cap and trade system would likely result in a shift away from coal-fired power production toward renewable energy and natural gas–fired power production.

The Waxman-Markey bill that passed the House of Representatives on June 26, 2009, and was originally slated for Senate consideration in 2009, now looks like it will be considered by the Senate in 2010. Among other things, the bill provides 85% of allowances at no charge, with the remainder to be auctioned. We believe that emission allowance limits in later years of the covered periods might make it unprofitable to produce electricity from natural gas.

The EIA predicts that natural gas use in the US will emit 1,318 million metric tons of carbon dioxide. This would not be a problem until later as total emission allowances fall below the level of only natural gas US carbon dioxide emissions sometime in the 2040–2050 period. If such a bill passes and is not repealed or changed, the gas industry could be thrown for a loop. However, problems would likely start very quickly, if not immediately, as scarcity of allowances would drastically increase energy prices, in our view. According to the bill, carbon dioxide equivalent emissions in 2005 were 7,206 million metric tons. (Other emission gases are assigned an equivalent equal to a certain number of carbon dioxide emissions; *e.g.*, one metric ton of methane is equal to 25 equivalents, and one metric ton of nitrous oxide is equal to 298 equivalents.) In 2012, the year that emission allowances are first issued under the bill, only 4,627 million metric tons of allowances would be issued. In 2050 and thereafter, the bill provides only 1,035 million metric tons of allowances, only 22% of the level that was allowed in 2012 and 14% of the total 2005 carbon dioxide equivalent emissions cited by the bill. We believe resultant (drastically) higher prices to purchase emissions allowances would likely impede future economic activity, which in turn could harm natural gas utilities.

The bill was delayed in the Senate until 2010 due to opposition using similar arguments to the discussion presented above. We think it is likely that continued opposition to the bill will either further delay any Senate vote or prevent any further consideration altogether. We believe that the failure of such a bill to pass would be fortunate for the US natural gas utilities in the long term. We believe that the bill's passage would initially benefit gas utilities as power generators would likely shift production fuel from coal to natural gas. However, as the number of available allowances would continue to decline significantly, we believe that prices of traded and auctioned credits would skyrocket as many industries compete for those allowances. The increased use of natural gas by power generators would also likely put upward pressure on natural gas prices. Those businesses that could not purchase enough allowances might have to shift production outside the US, especially for goods that are currently exported to other countries. We would also expect an increasing focus on conservation by consumers. We believe that, over time, the result would be lower demand for natural gas as it becomes much more expensive to use.

OUTLOOK: CAUTIOUSLY OPTIMISTIC

Gas distribution companies generally saw slow growth in 2007 and 2008, and to date in 2009. Standard & Poor's expects regulated gas utility subsidiaries to report earnings growth in the low to mid–single digits, helped by rate increases and customer growth, but offset by a weak economy and customer conservation efforts. Warm winter weather in the fourth quarter could also have a negative effect on 2009 results. While customer growth typically slows in a recessionary environment, most companies continue to experience some customer growth. The weak economy tends to increase the amount of bad debt expenses and reduce per-customer usage, especially usage for larger industrial customers as manufacturing activities are scaled back.

US demand for natural gas is expected to fall in both 2009 and 2010. The EIA forecasts that US natural gas consumption will decline by 1.9% in 2009 and 1.1% in 2010, after a 0.7% rise in 2008 and a 6.5% rise in 2007, which followed a 1.7% decline in 2006 due partly to warmer-than-normal weather.

A return to continued historically high natural gas prices could hurt gas companies. On November 16, 2009, Standard & Poor's forecasted Henry Hub bid week prices would average $3.77 per MMBtu in 2009, $4.06 in 2010, and $5.23 in 2011. Although gas prices and forecasts are muted compared to recent history, higher prices tend to attract fewer new customers to gas and discourage switching from other fuels, the current high prices for some competing fuels might still make those fuels less attractive than gas. High gas prices could increase the scrutiny that regulators apply to utilities' requests for gas supply reimbursement or for higher distribution rates.

Economic, natural, political, and geopolitical events could derail the natural gas price and volume forecasts for 2009. The slowdown in world economic growth and the strengthening of the US dollar from the summer of 2008 through early 2009, for example, led to oil prices falling from their record highs. However, since March 2009, the US dollar weakened significantly, adding to upward pressure in oil prices. So far, this has not translated into drastically higher natural gas prices due to high storage levels, weak demand, and the potential for additional LNG cargoes. Continued slow growth in both the US and global economies could continue to curb gas demand. Increased LNG liquefaction capacity worldwide may lead to more LNG imports, adding new supplies to the US markets. Additionally, new pipelines stretching from the Rocky Mountains eastward could reduce price volatility in the Northeast, putting a limited amount of downward pressure on prices.

Other developments, however, could increase upward pressure on prices. Because the Democrats gained solid control of the legislative and executive branches of government, there is a chance that the federal government could limit or discourage investment in US gas drilling through measures that would raise the cost of drilling in the US, making LNG and Canadian pipeline imports more attractive. Possible tensions between the US and oil-producing nations could lead to higher oil prices, which may also cause upward pressure on natural gas prices as end users with the capability to switch fuels could increase the demand for gas if it is less expensive relative to oil. ■

INDUSTRY PROFILE

A regulated industry confronts volatile prices

Natural gas distribution utilities include several kinds of operations: regulated, investor-owned companies; municipal gas distribution systems owned by cities and counties; and special utility districts. This *Survey* covers investor-owned gas distribution companies only; it does not cover interstate pipelines or natural gas production companies, nor does it cover any issues related specifically to municipally-owned gas distribution utilities.

Local distribution companies (LDCs) served 70.4 million customers in 2007 (as of November 30, 2009, data for 2008 had not yet been released), up 1.1% from 2006, according to the Energy Information Administration (EIA), a statistical agency within the US Department of Energy. Of this total, about 64.9 million were residential accounts using gas mostly for home heating and cooking. The remaining customers were commercial (5.3 million), industrial (0.2 million), and power generators. (See the "How the Industry Operates" section of this *Survey* for details.)

GAS UTILITIES OWN MORE THAN LDCs

	% OF 2008 OPER. INC. FROM GAS LDC OPERATIONS	GAS UTILITY	REGULATED ELECTRIC UTILITY	ELECTRIC POWER GENERATION	WHOLESALE GAS MARKETING	E&P	PIPELINE & STORAGE	OTHER
GAS UTILITIES								
AGL Resources	68	●			●		●	
Energen Corp.	15	●				●		
Equitable Resources Inc.	13	●			●	●	●	
National Fuel Gas	23	●		●	●	●	●	●
Nicor Inc.	67	●			●		●	●
Oneok Inc.	21	●			●		●	
Questar Corp.	7	●			●	●	●	
WGL Holdings Inc.	97	●			●			●
MULTI-UTILITIES								
Alliant Energy	13	●	●	●				●
MDU Resources Group Inc.	12	●	●			●	●	●
Scana Corp.	7	●	●		●		●	●
Nisource Inc.	36	●	●		●		●	●

E&P-Exploration & production.
Source: Company reports.

A series of regulatory reforms from 1978 (when regulations that set natural gas prices at the wellhead were first loosened) to 2005 (when the Public Utilities Holding Company Act, or PUHCA, was repealed, which dropped federal restrictions on utility mergers) have created a vastly different operating environment than that which prevailed 30 years ago. Natural gas prices are generally higher and more volatile, energy markets are more competitive, and corporate mergers have created huge, diversified energy companies with trading capabilities across several different energy sources. These developments have generated new risks—as well as new potential rewards—for gas distribution utilities.

Responding to this environment over the past decades, previously independent gas utilities have combined with other regulated utilities, as well as with new, unregulated energy-related businesses, to manage these new risks and profit from new opportunities. As a result, today's LDCs are usually part of a holding company that operates several different businesses. In some instances, LDC operations are the holding company's primary business. Secondary operations may include wholesale gas marketing, unregulated power generation, oil and gas exploration and production, interstate pipelines and storage, or even non–energy-related businesses such as timber or containerized shipping. In many other cases, LDCs are relatively small parts of large multi-utility or multi-industry companies.

INDUSTRY TRENDS

Several important trends in US energy markets are having a powerful influence on today's natural gas distributors. US natural gas prices are among the highest and most volatile in the world, due to the combination of rising gas demand and a lack of domestic production growth. On occasion, however, local events overseas, such as the shutdown of a nuclear plant in Japan and its using natural gas–fired plants to compensate, can lead to higher prices there. US gas demand is increasingly being met by imports, a situation that creates new risks and opportunities for LDCs or their affiliates. The growth in imports means that higher prices overseas could lead to competition for gas supplies, though new export facilities are easing this risk.

A trend among state regulators—to "unbundle" an LDC's supply function from its delivery function and thereby introduce retail competition into the supply of natural gas—has generated little interest in serving residential customers. Competitive suppliers are able to make substantially more money serving large commercial and industrial customers. At the same time, LDCs are and should remain rate-regulated businesses, with limited opportunities for growth within their service areas. Many LDCs have taken advantage of industry deregulation to acquire other kinds of businesses in hopes that diversification will drive stronger profit growth.

HIGHER AND MORE VOLATILE NATURAL GAS PRICES

The natural gas industry has undergone substantial changes in recent decades. Since regulatory reforms to the long-distance pipeline industry began in 1984, market forces have created a much more efficient supply system than existed previously. In the initial years of pipeline deregulation, increased efficiencies reduced transportation charges and inflation-adjusted gas prices. Lower and more transparent market prices fueled demand growth, while the elimination of structural constraints allowed natural gas supplies to be more fully developed, thus reducing levels of untapped capacity. Demand expanded to meet the limits of available supply.

With long-term forecasts for slowly increasing demand, growing production from more expensive wells, and steady domestic production, natural gas prices have been trending higher. Increasing summertime usage by power generators had reduced or eliminated storage additions during the summer months; this, combined with constrained natural gas pipeline and storage capacity in certain regions, has led to much more volatile natural gas prices.

This phenomenon has complicated the short-term operations and long-term investment planning for the entire natural gas industry, including regulated LDCs. Since December 2000, when cold weather blanketed the eastern United States and exhausted available gas supplies in some areas, natural gas prices have become noticeably more volatile; prices surged again to near-record levels during two subsequent winters. Since 2000, natural gas prices have been sustained throughout the year at higher levels than had been experienced in the past.

Price spikes

Since 2000, US natural gas prices have experienced severe spikes caused by cold winter weather, as well as one caused by hurricane damage to offshore production platforms and a spike that began toward the end of the 2008 heating season and culminated with an unusual mid-summer peak.

◆ **Cold weather spikes early this decade.** In December 2000, cold weather blanketed demand centers in the eastern and Midwestern United States, causing demand to spike and gas inventories to decline. By the end of that month, gas in storage was 10% less than the previous record low recorded in 1976. After averaging what was (at the time) an outstandingly high price of $4.50 per million British thermal units (MMBtu) in November 2000, natural gas for delivery at the Henry Hub (the national benchmark) in Louisiana more than doubled in December, reaching a then-record $10.52 per MMBtu on the New York Mercantile Exchange (NYMEX) on December 29.

Prices for gas delivered at the city gate (which is where LDCs take delivery from interstate pipelines) rose much further. With all available gas being committed to the frozen North, there was precious little to send to other demand centers. On December 11, 2000, the price for natural gas delivered to the southern

California border reached a previously unimaginable $68 per MMBtu. At the time, the Energy Information Administration (EIA), a statistical agency within the US Department of Energy, estimated that the average residential heating bill would rise by 70% for the winter—the biggest season-to-season gain since 1975.

After a relatively mild winter in 2001–02, another spike occurred when a cold snap hit in February 2003, driving the Henry Hub spot price on February 25 to $22.00 per MMBtu—nearly twice the level in 2000. However, prices dropped back to less than $6.00 per MMBtu the following week. Later that year, a blast of cold weather in December 2003 drove futures prices on the NYMEX up by 50% in two weeks, even though storage levels were above their five-year average and demand was running well short of peak levels. More cold air in the winter of 2003–04 pushed futures prices to $8.75 per MMBtu in February 2004, while gas delivered to New York City reached $40 per MMBtu.

◆ **Hurricane-related spike in 2005.** A sharp spike in prices occurred in September 2005, when two massive hurricanes, Katrina and Rita, struck a direct blow to the Gulf of Mexico's oil and gas industry over a four-week period beginning in late August. Together, the storms destroyed 115 offshore production platforms and damaged 52 other platforms and 183 pipelines. Damage was so severe that half of the Gulf's output, which provides about 25% of the US gas supply, was still out of operation two months later. The loss of supply drove gas futures prices above their previous record, set in December 2000, to $15.38 per MMBtu in December 2005.

◆ **Oil price–related spike.** Another longer-lasting price spike occurred initially in concert with record high oil prices, with prices starting their spike upwards after a short-term closing low of $5.34 per MMBtu (Henry Hub) on August 27, 2007. However, the upward run of prices paused during the last two months of 2007 in the $7.00 range. From the start of 2008 until the intraday market peak of $13.41 per MMBtu on July 2, 2008, gas prices rose dizzyingly fast, even though inventory levels were only 3% below their five-year average. (In fact, inventory levels were likely lower than the average as a direct result of the high gas prices.) Following the July peak, natural gas prices plunged even faster than they went up and faster than oil prices fell, reaching the recent Henry Hub intraday low of $3.15 per MMBtu by April 27, 2009.

What do these price spikes mean?

These price spikes made national headlines and caused considerable anxiety among regulators, politicians, and LDCs, and spawned at least one Senate committee hearing. Were suppliers gouging consumers? Had speculators driven up prices unnecessarily? Was there a gas crisis? The Commodity Futures Trading Commission, a government agency, investigated some of the spikes and found no evidence of market manipulation. Another investigation in the wake of the hurricanes had similar findings. However, a congressional investigation into high energy prices in the summer of 2008 heard testimony that blamed the 2008 oil price spike on foreign currency changes and to substantially increased participation of speculative funds in the oil markets.

High gas prices are an area of concern for gas utilities—even though their earnings are not tied directly to gas prices in the way that those of the exploration and production companies are—because they spur customers to conserve energy or search for other, cheaper sources of energy. Higher gas prices also invite closer regulatory scrutiny of gas purchases that, in hindsight, may be difficult to justify. A study on price volatility released in 2003 by the American Gas Foundation, an industry research group, said that volatility "has become the most significant issue facing the natural gas industry and its companies."

SUPPLY/DEMAND BALANCE IMPROVING IN THE FUTURE?

In the recent past, a supply/demand imbalance appeared to be building, with demand exceeding production and availability of Canadian pipeline imports being called into question. This led to an expansion of LNG capacity that would allow the US to receive overseas imports. However, new demand and production forecasts from the EIA could raise the question about whether additional LNG plants are needed. Additionally, the EIA predicts that production will nearly match demand in 2030, and that starting in 2026, the US will become a net exporter of gas by pipeline while getting only 1.0 Tcf of its imported gas from LNG. Of course, predictions can be changed, and a weak economy can reduce prices by quickly reducing demand leading to an inventory buildup.

Tighter supply/demand balance over past decade

While the spikes in prices alarmed gas consumers, they were all relatively short-lived. More worrisome, however, is a parallel development of sustained increases in average annual gas prices occurring year after year. Average US natural gas prices have risen in seven of the past ten years; and in 2009, S&P expects prices to be 66% higher than in 1999, despite the fact that S&P expects prices to be lower than in any of the past six years.

Behind the rise is a fundamental tightening of the balance between gas supply and demand. For the past several years, natural gas production in the United States has been stagnant—due, in large part, to declining output from the nation's largest and cheapest gas fields. During 1998 and 1999, oil and gas prices were depressed because of slumping global demand in the wake of the Asian economic meltdown in 1997. The losses suffered by many large producers from the drop in prices left them highly cautious about making new investments to expand production. The fact that they were becoming increasingly reliant on gas produced from risky and more expensive, deepwater wells, which cost hundreds of millions of dollars each to drill, only added to the caution. Moreover, through 2008 rig count had more than doubled since 2000, indicating that newer wells are producing at only a fraction of the rate for older wells. Adding to this, the recent relatively modest declines in total demand have led to a dramatic drop in rig count. Despite the drop in rig counts, production is expected to increase by 2.8%.

Since the mid-1990s, demand for gas from electric power generators has increased, as environmental regulations and high electricity prices encouraged the development of new power-generation capacity fired by natural gas. By 2008, the amount of gas used to generate electricity had risen by 64% since 1997, when the Department of Energy first started tracking this statistic, or a 4.6% annual growth rate. The rise in gas-fired generation capacity has not only kept the overall demand for gas from falling, thus tightening the supply/demand balance, but it has also made demand more volatile. Use by generators in 2009 through September has increased 3.2% despite a drop in usage across all other demand categories as relatively low gas prices made it more advantageous for power producers to run natural gas plants rather than some of their lower efficiency coal plants. With the rise in prices, the EIA expects this short-term phenomenon to reverse in 2010.

Much of the gas-fired generation capacity that was built is "peaking" capacity—used only for short periods of time when electric power demand is highest. These plants, which are cheaper and faster to build and more responsive to demand changes than coal-fired or nuclear power plants, are designed to be started and stopped on very short notice, thereby producing sudden increases and decreases in gas consumption.

Higher prices and greater volatility have brought increased attention to risk management techniques that can help prevent sudden and temporary spikes from raising residential heating bills. LDCs are starting to sign more long-term (12 months or longer) supply contracts and use futures contracts as a financial hedge, but they are still wary of doing so, lest prices move lower and regulators rule such contracts imprudent. After the relatively mild winter of 2001–02, which followed the record high prices reached the previous winter, many gas utilities were forced to explain why they had hedged their fuel cost at higher prices.

Lower demand forecasts

In its *Annual Energy Outlook 2008*, EIA predicted that electric power demand would increase to 6.5 Tcf annually from 2008 through 2016, before gradually declining to 5.0 Tcf in 2030. Additionally, it predicted that industrial demand would climb to and remain at close to 7.0 Tcf. This led to a rising total demand forecast that rose from 22.9 Tcf in 2007 to 23.8 Tcf in 2016, before retreating steadily back to 22.7 Tcf in 2030.

In the *Annual Energy Outlook 2010*, the EIA forecasts electric power usage to fall to 4.7 Tcf in 2014, before climbing steadily back to roughly 6.7 Tcf in 2030. It expects industrial demand to continue falling to 6.0 Tcf in 2010, before recovering to the 6.5–Tcf range from 2012 through 2030. EIA has also lowered its long-term demand forecasts for residential and commercial consumption as well. Total demand is now expected to decline to 21.0 Tcf in 2014 from 23.0 Tcf in 2008, before climbing gradually to 23.5 Tcf in 2030.

Production to start rising?

EIA also made a dramatic change to its long-term domestic dry gas production forecasts. In its *Annual Energy Outlook 2008*, it predicted that production would rise gradually from 19.0 Tcf in 2007, reaching a plateau of 20.0 Tcf in 2021 and 2022, before gradually declining to 19.4 Tcf in 2030. In its *Annual Energy Outlook 2009*, it expects domestic production to recede to about 19.1 Tcf between 2014 and 2017, before rising to 23.0 Tcf in 2030. Should this dramatic increase in domestic production occur, then it is likely that natural gas imports would fall.

Imports to start declining?

US natural gas utilities have been relying increasingly on imported natural gas to meet growth in demand, a trend that is projected to gain importance in the years ahead. Since the early 1970s, when long-term growth in US natural gas production ended, imports—mostly from Canada, but also in the form of liquefied natural gas (LNG) from Africa and the Caribbean—have increased steadily, both in overall terms and as a percentage of US supply. Since 1973, net imports of natural gas have nearly tripled in volume, growing by a cumulative average annual rate of about 3.3%. In 1973, net import volumes were 4.2% of total gas supply; in 2008, net imports accounted for about 12.6% of total gas supply and, in 2007, they were 16.5%.

In its *Annual Energy Outlook 2008*, the EIA estimated that net imported natural gas would represent about 20% of US gas supply by 2010, but shrink to 14.0% by 2030. However, in the *Annual Energy Outlook 2009* forecast, EIA now believes that net imports peaked in 2007, considering that it has changed its demand forecasts. At this point, the EIA sees net imports falling to 10.5% of total supply by 2010 and then to 1.6% of total supply by 2030. Between 2012 and 2021, it sees net imports remaining relatively flat at around 8% to 9%, before resuming their decline.

While oil imports can easily be increased to accommodate rising demand, the same is not true for natural gas. Transportation is a major cost component of natural gas, whereas it is generally incidental to the cost of oil. As a result, the favored source of gas is domestic production.

Canadian import growth slowing

During the period from 1987 until 1997, increased imports from Canada served to fill most of the supply gap left by stagnating US production, rising at a cumulative average growth rate of 11.3%. Imports from Canada rose every year from 1986 to 2003 and accounted for about 20% of total US supply in 2005.

However, Canadian import growth slowed to a cumulative average growth rate of 2.7% for the past 10 years and imports were flat from five years ago. Growth in domestic demand is beginning to erode the nation's export capacity; in 2003, gross natural gas exports to the United States fell by 9.2%, the first annual decline since 1986. Imports rose again in 2004 and in 2005, but did not regain the level reached in 2002. In 2006, imports from Canada declined 3.0% from 2005, as less natural gas was available for export, despite a slight rise in production. In 2007, levels rose 5.4%, approaching the imports seen in 2002, but fell by 5.2% in 2008. Year to date through September 2009, Canadian imports crumbled, falling by 9.0% versus the first three quarters of 2008.

As is the case in the United States, most of Canada's gas fields are mature. Forecasts show that production growth in Canada will fail to keep pace with higher consumption in the decades ahead, leaving less gas available to export.

According to Canada's National Energy Board (NEB), 77% of Canada's 2008 natural gas production came from Alberta, where there is growing local demand for natural gas to power development of the massive oil sands deposit. (In this process, natural gas is used to make steam, which is pumped underground to soften the heavy oil deposits so they can be recovered.) The NEB said in May 2009 that oil sands development consumed 1.1 billion cubic feet (Bcf) of additional natural gas per day in 2007—6.3% of Canada's total gas production in 2007. Project developers continue to look for alternative fuels, according to the NEB, such as bitumen gasification. In its *International Energy Outlook 2009*, the EIA estimated that by 2030 22% of Canada's natural gas consumption would be used in oil sands production, compared with 12% in 2006 (date cited by the EIA), thus diverting significant amounts of natural gas that might otherwise have been imported to the US market.

The EIA projects that these factors will reduce the net amount of natural gas imported by pipeline by a compound average rate of 19% per year from 2008 to 2025. In 2026, the EIA expects the US to begin exporting gas by pipeline.

LNG EXPANSION UNDERWAY

Despite the new EIA forecasts for lower demand, higher supply, and lower LNG needs, LNG facilities already under construction continue to be built. In the recent past, LNG facilities had been able to contract their capacity for decades. This meant that after the facility was built, the owner/operator of the facility would get paid whether or not any LNG was processed back into natural gas. The new EIA forecasts represent a major shift in its outlook, in our view, and if the economy has a strong recovery, the new forecasts might have to be revised to incorporate higher-than-expected economic activity.

With older forecasts showing that Canadian exports were unlikely to meet growing demands for US gas consumption, many companies determined that they could meet the demand imbalance by increasing imports of LNG by tanker. Many companies—ranging from holding companies that own LDCs to energy giants—were vying to take part in the growing LNG import industry. So far, most LNG plants that have been built or are under construction in North America have multi-decade contracts for a majority of the output from the plants.

The US imported a record 771 Bcf of LNG in 2007, which was 32% higher than the 584 Bcf received in 2006, 22% higher than the 631 Bcf in 2005, and 18% higher than the prior peak of 652 Bcf in 2004. However, LNG imports in 2008 were down 54% from year-earlier levels to 352 Bcf, seemingly ending the upward trend. LNG imports year to date through September 2009 were up about 30% from the same period in 2008. The EIA believes that volumes may be even stronger for the last three months, and projects a 34% rise in total volumes to 470 Bcf imported for 2009. In 2010, the EIA expects LNG imports to rise to 660 Bcf.

Although global liquefaction capacity has increased considerably since 2005—as the result of capacity additions in Egypt, Trinidad and Tobago, Nigeria, Qatar, and Yemen among other countries—maintenance delays and lack of available feedstock gas caused LNG production to grow at a much lower rate, according to the EIA. In recent years, there has also been strong demand for LNG in other countries, including Spain, France, Belgium, and the United Kingdom. LNG traders with options to deliver to multiple destinations found higher prices and more attractive markets in Europe and Asia in 2008 than in the US. However, EIA says that limited natural gas storage in those countries should allow the US to attract cargoes during the storage injection season (typically April through September) and that new liquefaction capacity may only have the opportunity to go to the US.

Despite the recent decline, the EIA predicts that LNG imports to the United States will almost double between 2008 and 2010, but will peak in 2018 at 1.4 Tcf, with a significant variation in year-to-year depending on domestic LNG prices relative to foreign prices, according to its *Annual Energy Outlook 2009*. According to a March 2008 report from Platts (which, like Standard & Poor's, is a unit of The McGraw-Hill Companies), the global regasification-to-liquefaction ratio is expected to rise to 3.22 in 2013 from 1.76 as of the date of the report. This suggests that there will be a lot of competition for cargoes of LNG.

US LNG infrastructure growing

Dozens of new projects to increase LNG supplies to the United States through expanded import infrastructure have been proposed. Some are already underway. As of November 2009, nine LNG import terminals with a combined sendout capacity of 14.8 Bcf/d, or 5.4 Tcf annually, were operating in the US. Additionally, there were two operating terminals in Mexico with a combined sendout capacity of 1.7 Bcf/d, or 0.6 Tcf annually, and one in Canada with a sendout capacity of 1.0 Bcf/d, or 0.4 Tcf annually.

Several new LNG import terminals are under construction and expected to begin receiving supplies in 2010 and 2011. The Federal Energy Regulatory Commission (FERC) has approved plans for a total of 17 new terminals and expansion projects, with a combined capacity of approximately 23.0 Bcf/d. Of these approved projects, only three terminals with a combined capacity of 4.2 Bcf/d are currently under construction.

Four offshore terminals with a total capacity of 4.2 Bcf/d have been approved by the MARAD/Coast Guard authorities. (MARAD is the Maritime Administration, which operates as part of the US Department of Transportation.) One of these, with a capacity of 0.4 Bcf/d, is under construction. Mexican and Canadian officials have approved a total of three terminals and one expansion project with a capacity of 3.0 Bcf/d; only one project under construction in Mexico has a capacity of 0.5 Bcf/d. Applications for another four onshore terminals with a capacity of 4.5 Bcf/d are pending FERC review, and another four offshore LNG terminals with a capacity of 6.7 Bcf/d are pending review by MARAD/Coast Guard authorities.

NORTH AMERICAN LNG TERMINALS

OWNER(S)	LOCATION	CAPACITY (BCF/DAY)
CONSTRUCTED		
Cheniere Energy Inc.	Sabine, LA	4.00
Southern Union Co.	Lake Charles, LA	2.10
Dominion	Cove Point, MD	1.80
Sempra Energy	Hackberry, LA	1.80
Cheniere Energy Inc., private investor group	Freeport, TX	1.55
El Paso Corp., Southern LNG	Elba Island, GA	1.20
Suez LNG North America	Everett, MA	1.04
Sempra Energy	Baja California	1.00
Irving Oil, Repsol	St. John, New Brunswick	1.00
Excelerate Energy	offshore Boston	0.80
Shell Gas B.V., Total SA, Mitsui & Co. Ltd.	Altamira, Tamulipas	0.70
Excelerate Energy	Gulf of Mexico	0.50
UNDER CONSTRUCTION		
ExxonMobil	Sabine, TX	2.00
El Paso Corp., Sonangol, private investors	Pascagoula, MS	1.30
El Paso Corp., Southern LNG	Elba Island, GA (expansion)	0.90
KMS GNL de Manzanillo	Manzanillo, Mexico	0.50
Suez LNG North America	offshore Boston	0.40
US ONSHORE / APPROVED BY FERC		
Cheniere LNG	Cameron, LA	3.30
Sempra Energy	Port Arthur, TX	3.00
Cheniere LNG	Corpus Christi, TX	2.60
Cheniere Energy Inc., private investor group	Freeport, TX (expansion)	2.50
AES Corporation	Baltimore, MD	1.50
ChevronTexaco	Pascagoula, MS	1.30
Crown Landing LNG, BP plc	Logan Township, NJ	1.20
4Gas	Corpus Christi, TX	1.10
Occidental Energy Ventures	Corpus Christi, TX	1.00
Gulf Coast LNG Partners	Port Lavaca, TX	1.00
TransCanada/Shell	LI Sound, NY	1.00
Northern Star LNG	Bradwood, OR	1.00
Sempra Energy	Hackberry, LA (expansion)	0.85
Hess LNG	Fall River, MA	0.80
US OFFSHORE / APPROVED BY MARAD/COAST GUARD		
Chevron Corp.	offshore Lousiana	1.60
Port Dolphin Energy	offshore Florida	1.20
McMoRan	offshore Lousiana	1.00
MEXICO / APPROVED TERMINALS		
Sempra Energy	Baja California (expansion)	1.50
CANADA / APPROVED TERMINALS		
Enbridge, Gaz Met, Gaz de France	Quebec City, Quebec	0.50
TransCanada/PetroCanada	Rivière-du-Loup, Quebec	0.50

LNG-Liquefied natural gas. Bcf-Billion cubic feet.
Source: Federal Energy Regulatory Commission (FERC).

Despite the large amount of existing, approved, and applied-for North American capacity (total of 62.3 Bcf/d), many of the LNG terminals that have been proposed are unlikely to be built. In fact, if they are not yet under construction, we believe they will not be built, at least for a long time. Unapproved United States plants face a host of obstacles beyond federal approval, including local opposition and lack of demand for so many projects. Approved projects face a lack of demand, especially if the EIA's new supply and demand forecasts prove anywhere close to being accurate.

With operating North American LNG capacity at 6.39 Tcf annually, and another 1.9 Tcf annually under construction, the amount of capacity available to the market far exceeds the peak demand forecast by EIA through 2030. Even if we assume that the capacity is only used during the four warmest months of the year (June through September), when demand is lowest in Europe and Asia, there would still be enough capacity to import 2.1 Tcf using existing plants and another 0.6 Tcf assuming plants under construction are placed into service. Two new North American LNG import terminals entered service in 2008 and two expansion projects entered service in 2009. Combined, these terminals added capacity of 6.8 Bcf/d.

◆ **Northeast Gateway Energy Bridge.** Excelerate Energy LLC's Northeast Gateway Energy Bridge Project, off the coast of Boston, entered service in April 2008. This project uses Energy Bridge Regasification

Vessels, which have the onboard capability to convert LNG back to the gaseous state. The resulting natural gas is then pumped from the ship directly into a subsea pipeline, which in turn is connected to an onshore pipeline to deliver the gas to end users. The facility's capacity is 0.8 Bcf/d. Due to the portable nature of the regasification facilities, it is unlikely that any of the capacity is contracted.

◆ **Freeport LNG.** Freeport LNG entered commercial service in April 2008. Its limited partnership interests are owned 70% by private investors and 30% by Cheniere Energy, while its general partnership interests are 50%-owned each by private investors and by Conoco Phillips. The project has an initial capacity of 1.55 Bcf/d. Located in Quintana, Texas, the project was built near two large natural gas trading hubs, Katy and Houston Ship Channel. There is no information on whether the facility has contracted any of its output.

◆ **Energía Costa Azul.** Sempra Energy's Energía Costa Azul on Mexico's west coast entered commercial service on May 15, 2008. The project has an initial capacity of 1.0 Bcf/d and may be expanded by another 1.5 Bcf/d. The project will connect to Sempra Energy's Baja Norte pipeline, which has connections to pipelines in the US. The facility is fully contracted for 20 years to Shell International Gas Ltd. (50% of capacity; Shell is a subsidiary of Royal Dutch Shell plc), and BP Tangguh project (50%).

◆ **Sabine Pass.** Cheniere Energy's Sabine Pass entered commercial service on November 6, 2008. The project has capacity of 4.0 Bcf/d after a 1.4 Bcf/d expansion project entered service in July 2009. Located in Sabine, Louisiana, the project will have access to several major pipelines through various pipeline interconnections with the company's Creole Trail Pipeline. Total SA (25%), Chevron (25%) and Cheniere Marketing have contracted all of the output from the existing plant and the 1.4 Bcf/d expansion (discussed below).

◆ **Cove Point.** Dominion's Cove Point LNG expansion project in Cove Point, Maryland, was completed in late 2008 and entered service in March 2009. It added capacity of 0.8 Bcf/d, bringing the terminal's total capacity to 1.8 Bcf/d. New capacity is contracted to Statoil for 20 years. The original plant is fully contracted to StatoilHydro ASA, Shell International Gas Ltd., BP, and peaking customers for 20 years starting in 2003.

◆ **Canaport.** Located in St. John, New Brunswick, Canada, the Canaport LNG terminal started commercial operations in June 2009. Irving Oil Ltd. and Repsol YPF SA (Spain) have partnered to develop this project. Repsol will hold all of the capacity in the plant. This terminal can accommodate imports of up to 1.2 Bcf/d. In July 2007, Canada's National Energy Board approved the Emera Brunswick Pipeline, which will connect the Canaport terminal with northeastern US and Atlantic Canadian markets.

◆ **Cameron**. Sempra Energy's Cameron LNG project in Hackberry, Louisiana has a capacity of 1.5 Bcf/d. Commercial operations began in July 2009. The project is 65 miles from a pipeline junction that gives it access to 65% of the gas markets in the US. Eni SpA has contracted 40% of the plant's capacity. Sempra has a short-term contract to buy up to 240 Bcf in 50 cargoes to help fill the remaining capacity.

Four new North American LNG import terminals and one expansion project with a combined capacity of 5.1 Bcf/d are scheduled to come online through 2011 to help serve the strong demand for natural gas in the northeastern US. According to the latest available numbers (December 2009), 11 northeastern states accounted for approximately 15.6% of total and 24.1% of residential natural gas consumption in 2007.

◆ **Neptune.** Suez Energy North America Inc.'s Neptune Project is scheduled to be commissioned in early 2010. This project, located close to the Northeast Gateway Energy Bridge Project, will deliver LNG imports from specially designed ships that will regasify the LNG through a subsea pipeline. The Neptune Project is designed to provide 0.4 Bcf/d. Due to the portable nature of the regasification facilities, it is unlikely that any of the capacity is contracted. On November 30, 2009, the first of two shuttle and regasification vessels designed to bring gas to the Neptune project, as well as other deepwater LNG ports, was delivered to Suez.

◆ **Golden Pass.** Golden Pass LNG project, owned by Qatar Petroleum (70%), ExxonMobil (17.6%) and Conoco Phillips (12.4%), in Sabine, Texas is expected to enter service in mid-2010 and have an initial capacity of 2.0 Bcf/d. LNG will be supplied by RasGas, owned by Qatar Petroleum (70%) and ExxonMobil (30%).

◆ **Elba Island.** El Paso Corp.'s Elba Island LNG expansion project in Georgia is expected to be completed in phases, with the first phase completed in mid-2010 and the second phase completed in 2012. The project should add capacity of 0.9 Bcf/d, bringing the terminal's total capacity up to 1.2 Bcf/d. The plant's existing capacity and the expansion's capacity have been contracted under long-term contracts to BG Group and Shell International Gas Ltd.

◆ **Gulf.** The Gulf LNG project, owned by El Paso (50%), private investors (30%), and Sonangol USA Co. (20%; Sonangol is a unit of Sonangol UEE), in Pascagoula, Mississippi, is expected to be completed in 2011 and have an initial capacity of 1.3 Bcf/d. The project has an existing pipeline infrastructure with access to markets in southeast Texas and other parts of the US. The plant is fully contracted for 20 years from the date it enters service.

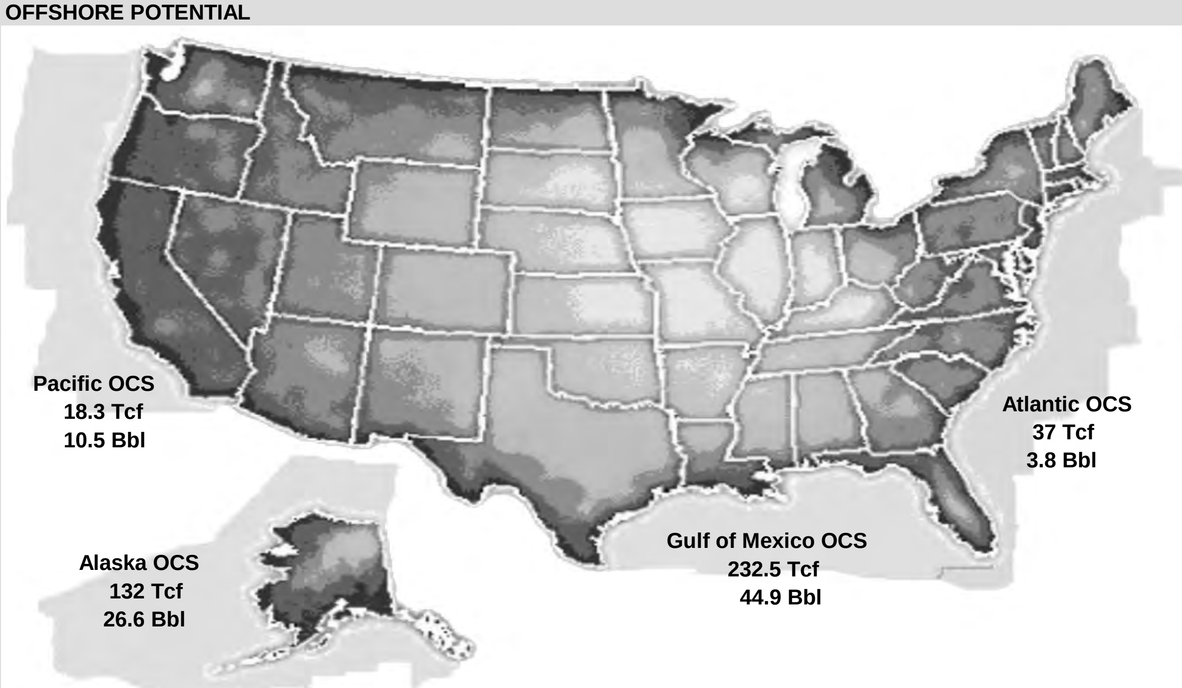
◆ **Manzanillo, Mexico.** The Manzanillo LNG project, owned by KMS GNL de Manzanillo, in Manzanillo, Mexico, is expected to be completed in 2011 and have an initial capacity of 0.5 Bcf/d. The project is expected to serve the Port of Manzanillo, a gas-fired power plant, as well as a bidirectional pipeline to be built between Manzanillo and Guadalajara.

Due to a previously widespread view that LNG imports were of increasing importance, on June 5, 2007, MARAD signed an agreement designed to allow state maritime academies and labor-based training facilities to develop liquefied gas training standards for US mariners. These training standards will be used to expand existing programs and to develop new programs to provide entry-level mariners with employment in the LNG industry, and to facilitate the retraining and/or recertifying of current mariners to permit their transition into LNG-related service.

OTHER NEW SOURCES OF GAS SUPPLY

As LNG's share of US natural gas imports may change, so too can the composition of domestic onshore gas production. LDCs must consider this fact as they formulate their views on future market conditions and prices. With gas output from traditional oil and gas wells declining, producers are increasing their investment in new,

OFFSHORE POTENTIAL



OCS-Outer continental shelf. Tcf-Trillion cubic feet. Bbl-Billions of barrels.
Source: American Gas Association, used with permission.

"unconventional" sources of supply: gas found in oil shale, coal beds, and "tight sands" gas—geologic formations that hold low concentrations of gas. These new sources have somewhat different production characteristics than traditional wells, as each well produces lower daily volumes but has a longer lifetime.

According to a December 17, 2008, EIA presentation accompanying the *Annual Energy Outlook 2009*, unconventional sources of gas accounted for about 50% of total US gas production—more than either conventional onshore sources or offshore sources. That share will grow to almost 55% by 2030, according to data in the presentation. The EIA assumes in its reference case that an Alaskan pipeline link will begin operations in 2020 and is expected to expand natural gas production in Alaska fivefold by 2030. If the pipeline does not get built, EIA expects that additional production of gas from unconventional sources and additional LNG imports will fill the gap.

Even including the new sources, total US dry gas production is expected to increase by an important but still anemic average annual rate of 0.5% between 2008 and 2030. This low growth rate has led to calls from a variety of sources—including both energy-producing and energy-consuming groups—for the United States to open up more of the country for exploration and production.

PIPELINE CAPACITY EXPANDING...

Pipeline capacity for natural gas is being expanded in part to bring gas to the northeastern US. Some of the new pipelines will allow expected LNG imports to move from LNG terminals to major gas pipelines, while others should help to move new gas discoveries in the western and mid-continent US supply regions to distributors and end users in the Northeast and on the West Coast. Completion of these pipelines could help to reduce city-gate price volatility in the Northeast.

New pipeline projects approved by FERC include 2,781 miles of new pipeline in 2007 and 2,084 in 2008. Of the 35 projects that were approved in 2007, only 11 were longer than 100 miles. In 2008, nine projects were approved, of which five were in excess of 100 miles. Shorter projects include smaller new pipeline projects, expansions, extensions, interconnections, and laterals to reach new LNG or storage facilities or other pipelines. However, year to date through December 8, 2009, only five projects (718 miles) have been approved, with only one over 100 miles. FERC says that there were an additional 3,921 miles of pipeline projects "on the horizon" as of November 2009. Some major pipeline projects (over 500 miles) are detailed below.

◆ **Rockies Express Pipeline**. Jointly owned by Kinder Morgan Energy Partners, Sempra Energy, and Conoco Phillips, the Rockies Express Pipeline is a 1,679-mile, 1.8 Bcf/d natural gas pipeline system that runs from Rio Blanco County, Colorado, to Monroe County, Ohio. Rockies Express–West (713 miles) was approved in April 2007 and was placed in service on May 20, 2008. Rockies Express–East (638 miles) was approved in May 2008 and entered full service in November 2009 after several delays related to weather. The Entrega (328 miles) segment of the Rockies Express Pipeline was fully operational by February 2007.

◆ **Midcontinent Express Pipeline**. Jointly owned by Kinder Morgan Energy Partners and Energy Transfer Partners, the Midcontinent Express Pipeline is a 507-mile, 1.5 Bcf/d natural gas pipeline system that runs from the southeast corner of Oklahoma across northeast Texas, northern Louisiana, and central Mississippi into Alabama. The pipeline was approved in July 2008 and entered full service in August 2009.

...but more slowly

At least three other 500-mile–plus pipelines were announced in 2007 or 2008. However, two of these projects were either cancelled or postponed due to a drop in the amount of natural gas expected to be flowing out of the Rockies region.

◆ **Ruby Pipeline**. This project, owned by El Paso, is a 680-mile, 1.2 Bcf/d natural gas pipeline system that starts at the Opal Hub in Wyoming and terminates at the Malin, Oregon, interconnect near California's northern border. The FERC application was filed on January 27, 2009.

◆ **Sunstone Pipeline**. Jointly owned by Williams Cos., TransCanada, and Sempra Energy, and announced in 2008, the Sunstone Pipeline project has been suspended as the project partners reevaluate the project's timing and scope. The project is a 585-mile, 1.2 Bcf/d natural gas pipeline system that runs from the Opal Hub in Wyoming to Stanfield, Oregon. The project had originally been expected to be completed in 2010.

◆ **Bison/Pathfinder Pipelines**. TransCanada Corp.'s Pathfinder project—a 673-mile, 1.6 Bcf/d natural gas pipeline system running from Meeker, Colorado, to an interconnection in North Dakota with the Northern Border Pipeline Co. (NBPL) system—was effectively cancelled in 2008 when it was merged by the company with its Bison project. The smaller Bison project, with a capacity of 0.5 Bcf/d, will extend 303 miles from Gillette, Wyoming, into North Dakota, where it will connect with the NBPL, which can carry gas to the Midwest. TransCanada expects the Bison project to commence operations in November 2010.

CUSTOMER CHOICE PROGRAMS FALL FLAT

The drive to introduce competition to the utility industry during the 1990s led several states to order their LDCs to "unbundle" (formally separate) their supply function from their distribution function in order to allow other independent suppliers to enter the market and retail competition to develop. The idea was that customers would end up paying less for their natural gas supply if they were allowed to shop among different suppliers for the best price, rather than simply buying from the distribution utility at the utility's cost. While the idea seemed logical in theory, it is becoming increasingly clear that, at the residential level, retail unbundling has failed to generate the competition and related advantages that regulators expected.

Except for the largest gas consumers—industrial companies and power generators for whom natural gas is a major expense—customer interest in switching suppliers has been disappointingly low. Even more discouraging for the proponents of retail-level gas supply competition, the number of active retail suppliers competing for customers had been shrinking through 2006, rather than expanding as they had expected. However, in 2008 the number of active suppliers increased for the second year in a row, seemingly reversing this trend.

Across the US, about 35 million gas customers in 21 states and the District of Columbia—just over half the US total—are able to switch suppliers, but, at the end of 2008, only 13.5% of those eligible for customer choice programs had actually done so, according to the latest data from the EIA. Just three states—Georgia, Ohio, and New York—now account for 73% of the customers who have switched suppliers.

The number of gas customers buying their gas from a source other than their LDC in 2006, 2007, and 2008, increased by 327,000, 459,000, and 49,000, respectively. During that period, gains in just four states represented 90% of the total increase. In Ohio, switching participation increased from 36.3% to 48.4% for a total increase of 295,000 (35% of the period's total gain). In New York, switching participation increased from 7.8% to 13.7% for a total increase of 260,000 (31% of the period's total gain). Switching participation increased in Illinois and Michigan, and accounted for the remaining 24%. While switching in these four states and, to a lesser degree, in four other states, appeared to be gaining ground, the remainder of the states did not show meaningful increases in switching activity. The number of customers that switched suppliers totaled 4.7 million at year-end 2008.

State programs to allow and encourage retail supply competition have fallen into disarray. Just three states (New York, New Jersey, and Pennsylvania) and Washington, D.C., now have active programs in which all residents are eligible, by law, to choose their supplier. Participation was less than 10% in each area, except New York, which broke the barrier in 2008. Four other states (New Mexico, California, West Virginia, and Massachusetts) also have legislated 100% eligibility, but their programs are inactive, and participation rates are all less than 1%. Finally, six states (Georgia, Illinois, Maryland, Michigan, Ohio, and Virginia) allow more than 50% of their customers to switch; of these states, only Georgia (81.5%), Ohio (42.3%), and Maryland (10.9%) had switching levels above 10%.

COMPANIES CHANGE COURSE

In recent years, several utility companies have changed course on ownership of nonutility businesses. In many cases, these businesses had high capital requirements due to required collateral postings. Some have sold these businesses outright, one scaled back its operations while trying to sell, and one placed its business into a joint venture in an effort to reduce risk and refocus the companies on their core equity businesses. In most cases, the companies have used the cash from asset sales for share repurchases and dividend hikes. In some cases, companies have paid down debt, but in others, the business risk of the overall company has dropped, allowing them to increase their debt load.

Merger activity stalls…

There was very little significant merger and acquisition activity among key gas utility companies in 2007, 2008, and 2009. In 2007, some deals took longer than expected to close, while others were cancelled. In addition, companies divested E&P businesses in 2007. In 2008, only two significant transactions took shape. Activity has likely slowed due to stock price weakness (companies often use stock as currency in acquisitions) at the same time that companies cut capital spending plans, borrowing costs increased, and access to capital became more difficult.

Should gas prices return and remain at high levels, we think that a resumption of industry consolidation could occur. For a utility with no or very small non-utility businesses, we believe that growth through merger savings could be their only viable option to achieve higher-than-industry-average earnings per share (EPS) growth. There also have been some discussions of spinning off utility businesses from companies whose unregulated E&P businesses now dwarf their utility operations, but we don't think such an event is likely in the near future.

On October 1, 2008, Sempra Energy completed its purchase of EnergySouth for $510 million in cash. In addition to a small distribution utility in Alabama (93,000 customers), Sempra gained two large, high-cycle underground natural gas storage facilities that, when fully developed, will have capacity of 57 Bcf. At the time of the deal's closing, only 11.4 Bcf of storage was operational; the remainder is slated to come into service during 2010 and beyond.

A $970 million deal in 2007 for the sale of two natural gas utilities owned by Dominion Resources was cancelled in 2008 after resistance from the Federal Trade Commission on antitrust grounds. However, on July 2, 2008, a private equity fund agreed to purchase the same assets for $910 million. Dominion expects the deal to close by the end of 2009.

Are cross-border deals the shape of things to come?

In August 2007, National Grid PLC acquired KeySpan (with 2.6 million gas customers in New York, Massachusetts, and New Hampshire) for $7.3 billion in cash. In September 2008, Spanish firm Iberdrola SA purchased Energy East Corp. (with 1.8 million electricity customers and 900,000 natural gas customers in New York, Maine, and Connecticut) for $4.5 billion. These deals are of particular interest because they may augur similar deals in which large foreign utility companies seek to diversify through the acquisition of US utility businesses. Iberdrola has stated that it viewed the US as one of its best opportunities for growth.

Standard & Poor's believes that cross-border deals are likely to continue, though not in the current economic environment. However, we believe more international utility acquisitions will be announced in the event of an economic recovery. Foreign acquisitions have the potential to spur domestic consolidation: local companies may combine to avoid becoming takeover targets for larger foreign utilities.

LDCs slow diversification efforts

Because their returns are regulated and their industry mature, natural gas distribution utilities traditionally have had severely limited growth prospects. Historically, earnings for US LDCs have grown with the help of only population growth and rate increases. As a result, share prices have tended to lag shifts in the larger market.

Until the 1990s, there was little that executives of LDC companies could do to raise their growth rates and boost shareholder returns, and their shares were usually held for current income rather than growth. That changed, however, during the latter half of that decade, when regulatory reforms began allowing LDCs to form holding companies that could invest in other, unrelated businesses offering stronger growth prospects—accompanied by greater risks.

For several years, gas and power utilities embarked on a campaign of often-indiscriminate spending, negotiating mergers, building and buying new unregulated, "merchant energy" power-generation assets, acquiring overseas operations, and establishing (and funding) trading desks, as well as expanding into novel areas such as telecommunications, construction, and even healthcare. This strategy of diversification proved to be far less profitable than originally envisioned, however, and many companies were forced to sell or even abandon recently purchased assets in order to reduce their crippling debt loads.

The frenzied corporate realignment of the 1990s came to a halt in 2001, when the bankruptcy of Enron Corp. and the power crisis in California undermined investor confidence in the benefits of asset diversification. During 1998 and 1999, a total of 18 mergers involving US LDCs were announced; between 2000 and 2004, there were only six.

This wave of activity changed the face of the natural gas industry, but no dominant business model has emerged. Many gas distribution companies are owned by large multi-industry companies or multi-utility companies, such as Dominion Resources, Sempra Energy, Questar Gas, Equitable Resources, and MDU Resources Group. These companies have a broadly diversified asset base, which includes regulated gas and electricity distribution utilities (domestic and foreign), unregulated power generation assets, exploration and production operations, long-distance pipelines and storage, LNG import terminals, and even construction materials supply. Another group—which includes Nicor Inc., AGL Resources, and WGL Holdings Inc.—is more gas-focused, combining regulated gas distribution utilities with long-distance pipelines and unregulated businesses of varying sizes.

In recent years, several companies have exited or are in the process of exiting some of their nonutility businesses in an effort to refocus on their utility operations. We believe these moves indicate a realization among executives that many of these businesses were using capital that could otherwise be redeployed within the companies for growth in the utility businesses or to fund dividends and/or share repurchases.

In 2007, Dominion Resources Inc. completed a corporate restructuring that included the divestiture of its non-Appalachian exploration and production (E&P) assets for roughly $13.9 billion in several transactions. The company is using the proceeds for share repurchases, debt reduction, and general corporate purposes. Similarly, in August 2007, Integrys Energy Group Inc. sold Peoples Energy Production Co., an oil and natural gas exploration business included in its acquisition of Peoples Energy, to El Paso Corp. for $875 million. Integrys also announced in late 2008 that it was planning to sell or shut down its nonutility energy services business. On April 1, 2008, Sempra Energy, in a risk-reducing move, placed its commodity trading into a joint venture with a partner that had a stronger credit profile, so that it could use about $1 billion in returned collateral to repurchase shares.

HOW THE INDUSTRY OPERATES

Natural gas is a colorless, odorless fuel composed primarily of methane and ethane. It burns more cleanly than many other fossil fuels—emitting less carbon dioxide than coal or oil, and little sulfur or particulates—making it one of the most popular sources of energy today. Natural gas provided about 24% of the US energy supply in 2008, a share that is expected to drop to 22% by 2030, according to the Energy Information Administration (EIA), part of the US Department of Energy.

THE NATURAL GAS SUPPLY CHAIN

The natural gas supply chain comprises three distinct segments: upstream, midstream, and downstream. Parts of the chain include wells, processing plants, pipelines, liquefied natural gas (LNG) facilities, storage facilities, and distribution facilities.

E&P: the upstream segment

Exploration and production (E&P) companies search for gas underground and bring it to the surface through wells. The supply of natural gas in the United States comes chiefly from domestic E&P operations. Domestic dry gas production accounted for 87.3%, or 20.4 trillion cubic feet (Tcf), of total US supply in 2008, according to the EIA, while net imports via pipeline contributed 11.4%, or 2.7 Tcf. Net LNG imports made up the remaining 1.3%.

Within the US, natural gas is produced in 35 different states, but just seven (Texas, Alaska, Wyoming, Oklahoma, New Mexico, Louisiana, and Colorado) accounted for 75.7% of total output in 2007, according to the latest available data (December 2009) from the EIA. The federally administered Gulf of Mexico Outer Continental Shelf (OCS) region provided a further 11.6% of total production. In addition to supplying the domestic market, US natural gas producers also export small amounts of gas to Canada and Mexico via pipeline, and to Japan and Mexico as LNG.

Raw gas from underground reservoirs is moved through a series of feeder (gas gathering) pipes to processing plants that remove impurities and natural gas liquids (NGLs—such as propane or butane). The propane and butane can be stored and sold on site or moved through NGL pipelines to other locations. The almost pure methane gas that results—known as "pipeline gas"—is then sent to long-distance transmission pipelines.

Pipelines: the midstream

The midstream segment comprises interstate pipeline, or "transmission," companies, which build and operate pipelines to transport gas from producing regions to demand centers. Transmission companies are regulated by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over interstate commerce in natural gas. The EIA estimated there were 217,306 miles of interstate pipelines in the lower 48 states at the end of 2008 and an additional 88,648 miles of intrastate pipelines.

Attached to the pipeline systems are many natural gas storage facilities, which are used to store gas during periods of nonpeak demand in order to be able to maintain supply during peak demand times. At the end of 2007 (latest available data as of December 2009), there were about 400 storage facilities with 8.4 Tcf of total storage capacity, or 3.7 Tcf of working gas capacity, according to the EIA. Working gas capacity is total gas minus base gas capacity. Base gas capacity is an amount of gas needed to maintain adequate pressure in a storage reservoir during the withdraw season.

Although US gas storage capacity is located in 30 states, eight states (Michigan, Illinois, Pennsylvania, Texas, Louisiana, Ohio, West Virginia, and California) account for more than two-thirds of the total. Numerous gas storage projects are in the works to accommodate increased gas usage and to improve reliability. The added storage capacity is likely to result in additional gas purchases during off-peak months to refill the storage fields in advance of the winter season, thus helping to smooth seasonal price fluctuations by increasing nonpeak demand and decreasing peak demand.

LNG terminals and ships: another piece of the midstream

LNG is simply gas that has been cooled to 260 degrees below zero on the Fahrenheit scale; at this temperature, it condenses into a liquid from a gas. Gas is condensed at liquefaction facilities in countries that export the gas. Once condensed, the liquid takes up about 1/600 the space of the gas at atmospheric pressure.

LNG is transported on specially made ships. Some of the liquefied gas stored on the ships is returned to a gaseous form and is used as fuel for the ship or its cooling system. At the end of its journey, the LNG is transferred to a regasification facility, where the gas is warmed (and thus returned to a gaseous state) and then either stored in storage facilities or put directly into gas pipelines for transportation to other markets.

In recent years, numerous LNG terminals (which include regasification facilities) have been proposed for construction. Many proposed for locations outside of the Gulf states have run into local opposition and may not be built. Several are under construction, however, and others are likely to be built.

International competition for LNG is strong, with the ships serving the highest-priced markets first. However, most LNG regasification facilities have long-term contracts that guarantee payment to the facilities' owners whether the facility is used or not.

LDCs: the downstream segment

Local distribution companies (LDCs) occupy the downstream segment of the gas industry, taking gas from interstate pipelines and distributing it to a broad range of customers, including residential, commercial, industrial, and power generation. They perform this service under a monopoly concession and are subject to rate regulation.

LDCs are sometimes run as stand-alone operations, but independent LDCs have become increasingly rare in recent years. Following regulatory reforms that eased restrictions on mergers by gas and other utilities, most LDCs are now owned by larger holding companies that also own other businesses, including other regulated gas and electric utilities, as well as unregulated businesses that may or may not be related to energy.

It is important to remember that LDCs perform two related, but distinct, services: the delivery of gas, as well as the procurement and sale of gas to the customer. LDCs deliver gas to customers through pipeline networks they build and maintain, and attempt to earn a profit for providing that service. In addition, they procure gas and sell it to customers at cost, a service for which no profit is earned. In both cases, the rates that they can charge are regulated by state officials, and LDCs have no guarantee that state regulators will allow them to fully recoup the cost of gas sold to customers.

REGULATION: A PART OF DOING BUSINESS

LDCs operate under monopolies that are granted by a state or municipality and cover a particular service area. State utility commissions regulate just about every aspect of an LDC's activities, including what it can charge for delivery and for gas supply. Often known as Public Utility Commissions (PUCs) or Public Service Commissions (PSCs), state regulators are responsible for ensuring the safe and reliable access to gas on an equitable basis and, in some cases, for promoting competition.

State utility commissions usually consist of a board of three or more members appointed by the state's governor and confirmed by the legislature. (In some states, utility commissioners are elected by popular vote.) The commissions often employ a large staff, including attorneys and accountants, to evaluate information filed by utilities regarding potential rate changes and to assist commissioners in making decisions. Utility commissions may regulate one or more natural gas utilities as well as other businesses, such as electric and water utilities, telecommunications providers, and cable television operators.

In addition to setting rates of service, a state utility commission issues regulations covering other important aspects of an LDC's operations. It oversees environmental performance, monitors the LDC's operations to ensure that it complies with relevant laws, and enforces universal service obligations. It has authority to approve or deny corporate mergers, the sale of facilities from one party to another, and even such financing activities as bond issues or intracompany fund transfers.

Ratemaking

The greatest power that state utility commissions hold over LDCs is the ability to set the rates LDCs are allowed to charge for delivery and for gas supply. As a practical matter, the delivery charge is the more complex to set, since it must allow the LDC to earn a profit. Gas supply charges, while not free of controversy, are more an issue of reimbursement, though disputes can and often do arise over whether a gas supply charge was prudently incurred. In 2007, most states created rate frameworks that seek to minimize disagreements and allow customer charges to more closely reflect volatile natural gas prices.

A natural gas utility's rates for its delivery service are mostly set on a "cost of service" basis; that is, rates are calculated to generate enough revenue for the utility to recover its operating costs and earn a fair return for shareholders. This makes the relationship between a utility and its regulatory commission an important determinant of both its current profitability and its long-term growth prospects.

In general, the ratemaking process begins with a request from the regulated utility for a change in rates when the current rate schedule expires. The process of deciding what rates a utility will be allowed to charge is known as a "rate case." In addition to the change in rates requested, there may be simultaneous negotiations between the company and the commission on any other issues that one or both sides want to address, such as customer complaints, infrastructure investment, environmental issues, or reliability problems.

The first step in the rate case is determining the cost to maintain and operate the distribution system as well as the cost of any capital improvements that are needed. This amount is calculated by totaling the company's operating and maintenance expenses, asset depreciation, and taxes over a hypothetical period known as a "test year" that has been normalized to eliminate any unusual or one-time incidents. The commission must decide whether to allow each expense item submitted by the LDC; if an item is denied, its cost must be borne by the utility's shareholders. Disputes often arise over whether a particular cost should or should not be reimbursed by ratepayers.

Setting a utility's rate of return

Once the utility's expenses have been determined, the utility's management and regulators must then negotiate an appropriate rate of return for the utility, a rate that will provide an adequate incentive for investors to own equity in the LDC and thus ensure it is adequately capitalized to provide acceptable service. Deciding what level of return the company should receive is often the most controversial part of the rate case—and a process that is as much art as it is science.

For investor-owned utilities, the return is usually calculated as the percentage of the utility's assets used to deliver service that is needed to cover the utility's cost of capital. Cost of capital is defined as the sum of the cost of debt service, preferred stock dividends, and a fair return for common stockholders. While the cost of debt service and preferred stock dividends is easy to establish, the appropriate return for common stockholders is more difficult to ascertain. Commissions use such methods as comparable company analysis, discounted cash flow, and risk premium analysis (such as the capital asset pricing model) to determine an appropriate return on common equity. In some instances, a utility commission may desire to set a rate of return that is not equivalent to the utility's cost of capital, as either a reward or punishment for management decisions and operating performance.

It is important to remember that in setting the rate of return, the utility commission does not guarantee that the LDC will actually earn that rate, but instead gives the LDC the opportunity to earn that rate. Sound management and operating skill are needed to achieve the allowed rate of return, and poor decisions can leave the realized rate of return significantly below the allowed rate.

Once the utility's full revenue requirement (costs, plus a fair return) has been identified, that sum must then be allocated among the different classes of gas consumer: industrial, residential, commercial, and power generators. Industrial rates tend to be the lowest, because industrial customers are high-volume users and are easier to service than residential accounts. Allocations can be controversial, since one customer group may argue that it is being forced to subsidize another.

After it has been determined how much each class of customer will pay in total, the structure of the charges is determined in a process known as "rate design." Rate designs vary considerably and can include fixed per-customer charges, minimum bills, charges per therm (a unit of heating value), or some combination of these.

Alternatives to cost-of-service ratemaking

Cost-of-service–based ratemaking has several important disadvantages when it comes to the incentives it offers for efficient utility performance. Just determining the actual cost of service is cumbersome, time-consuming, and adversarial, and is complicated by the fact that many investor-owned utilities operate more than one LDC—thus raising issues about what costs should be allocated to what operation. Furthermore, cost-of-service ratemaking provides a strong incentive for a utility to inflate the size of its asset base by so-called gold plating: overinvesting in assets that are either unnecessarily expensive or redundant, because the larger the rate base, the higher the return.

To counter this problem, some states have begun to experiment with incentive-based rates that seek to promote efficiency, either through rewards for the attainment of performance goals or through punishments for the failure to achieve expected standards. Various kinds of performance-based structures exist, each with unique advantages and disadvantages.

◆ **Regulatory lag.** One of the simplest ways to create more incentives for improved performance is known as "regulatory lag," or the extension of the minimum time between rate changes. This produces a strong incentive to cut costs, because utilities will keep 100% of any cost savings made during the period; they also would bear 100% of any additional costs incurred.

◆ **Price cap.** Another kind of incentive-based ratemaking formula is the price cap, in which the charge for distribution is set through a formula that adjusts the previous charge according to inflation (usually based on the consumer price index) and also according to expected gains in productivity. This has the effect of forcing a utility to make productivity gains—because prices already are calculated to reflect them. Further gains, however, would increase the utility's return, providing a strong incentive to increase productivity beyond the set target. The success of this formula depends on the correct setting of the expected productivity gain factor in determining future prices. A factor set too low would allow the utility to earn above-normal profits, while a factor set too high might prevent it from fully recovering its costs. Price caps are more common outside the United States.

◆ **Revenue cap.** An alternative to the price cap is the revenue cap, which can take the form either of an absolute revenue cap or a revenue-per-customer cap. With revenues fixed, profits will rise only if costs are cut.

◆ **Earnings sharing**. Another kind of incentive-based rate that has gained popularity in recent years is "earnings sharing." When regulators determine a utility's rate of return for a given period, the specified return is actually a target return that the rate schedule is designed to produce.

Because actual events may lead to a different return, regulators may set a band that is designated as an "allowed rate of return," which regulators view as an acceptable variation from the target. If actual returns fall below that band, the utility may be allowed to petition for a rate change. If returns are above the target band, the "excess" earnings are shared, in part or in whole, with customers in the form of future rebates. This protects the utility from unexpectedly low returns and lets customers benefit from improved efficiency.

Each of these alternatives has potential drawbacks, and studies examining alternative regulatory regimes have found it difficult to determine their overall effects. Because incentive-based rate designs do not offer a clear opportunity to enhance returns and usually entail some risk, some utilities have preferred to remain under traditional regulation.

Helping utilities to encourage efficiency

Some states have acknowledged that increasing efficiency in appliances that use natural gas has led to declining consumption of gas per customer over time. As a result, the fixed-cost component of a utility's expenses has been increasing over time relative to its revenues. Since rates typically are largely tied to utilities' throughput, utilities have been having a harder time recovering the fixed investments that they make in distribution pipeline and service connections. Therefore, a utility with rates mostly tied to variable usage is averse to helping customers to conserve gas.

As a result, some states have implemented revenue-decoupling mechanisms that increase the fixed charges on customers' bills. In exchange for this concession, utilities that have revenue decoupling mechanisms in their rates have agreed to invest in programs that may give rebates to customers for installing more efficient, but more expensive appliances, thus encouraging conservation. The higher fixed charges on customers' bills are designed to allow utilities with this rate mechanism to collect enough for maintenance costs, new connections, and a fair return on fixed plant investment.

WEATHER INFLUENCES EARNINGS

With delivery rates typically tied to the volume of gas delivered, and costs that are mostly fixed, LDCs' earnings traditionally have been highly sensitive to changes in the weather. Colder-than-normal winter weather has the effect of increasing volume (and therefore, sales), while warmer-than-normal weather can cut volumes significantly, eroding profitability.

In setting rates, regulators assume a particular level of demand and gas distribution volumes. Unusual weather patterns can make this assumption either too high, leaving the utility with a revenue shortfall, or too low, giving the utility a revenue windfall. To smooth these peaks and valleys, many states have started to include "weather normalization" clauses that serve to reduce weather-related effects and redress earnings volatility. A shift in weather patterns that causes a greater- or less-than-expected number of degree days (a measure of the variation of the mean daily temperature from a reference temperature) triggers a surcharge (in the case of unusually warm weather) or credit (when the weather is cold), applied to customer bills to offset the effect of weather. A more recent option for utilities seeking to minimize the effects of weather on earnings is to use weather-based financial derivatives.

Because revenues are tied to delivered volumes, LDCs have a strong incentive to discourage energy efficiency and conservation, something state regulators would like to change as natural gas prices rise. In recent years in some states, a new "conservation tariff" has been used that decouples an LDC's revenue from its delivery volumes by protecting profit margins in the event that delivery volumes decline. This is accomplished by mechanisms that change the price of gas delivered according to actual volumes delivered, or by "deferral accounts" that keep track of the impact of conservation measures and provide for deferred collections or refunds at set times.

MANAGING GAS SUPPLY

In addition to maintaining a pipeline network, an LDC is responsible for managing the supply of gas moving through its network, in order to maintain adequate pressure in the system and meet the full requirements of customers during times of peak demand. LDCs are responsible for delivering gas that customers have purchased from an independent competitive supplier, as well as supplying gas to customers that are either unable to choose a competitive supplier or fail to do so. When supplying gas directly to customers, an LDC must purchase the gas itself, as well as pay for transportation of the gas to the LDC's network (and possibly for storage as well).

Deregulation creates choices

Before 1984, when deregulation of the interstate pipeline industry first began, LDCs were forced to buy their gas directly from the transmission pipeline company that served their area as part of a package that included both the gas itself and pipeline transportation to the LDC's city gate. These purchases were made under long-term contracts that obliged the LDC to pay for a certain amount of gas even if the gas was not needed.

In 1984, FERC's Order 380 freed LDCs of those "take-or-pay" contractual obligations, thereby allowing them to start buying gas directly from producers on the spot market, once their take-or-pay obligations were satisfied. The FERC went on to issue a series of orders dismantling pipeline regulations. This process culminated in 1992 with Order 636, known as "The Restructuring Rule," which required pipelines to offer transportation service as a separate service on terms equal to those given customers buying gas from the pipeline.

Since that time, a wholesale market for natural gas in the United States has developed that allows LDCs to purchase gas on a variety of terms and from a variety of different sources. A new class of independent gas marketer sprang up to compete with gas producers and pipelines by offering different products that allow LDCs to create their own supply portfolios, reflecting each LDC's individual circumstances and needs. LDCs have taken advantage of the shift to diversify their sources of supply away from pipeline companies; now they source a significant amount of their supply either directly from a producer, a producer's marketing affiliate, or from an independent marketer.

According to an American Gas Association (AGA) survey of its members on hedging and supply procurement practices in the winter season of 2005–06, most LDCs now buy the majority of their supply directly from the marketing affiliate of a gas producer or from an independent marketer. Of the 29 companies responding to a question about their source of gas supply during their peak day of consumption, just two reported buying any portion of their supply directly from a pipeline company, while seven said they purchased from the marketing affiliate of a pipeline company. In both cases, only one company reported purchasing more than 25% of its peak day supply from a pipeline company or its marketing affiliate. Only four respondents said they did not purchase any supply from an independent marketer, and just six said they had no dealings at all with a producer.

Supply contract options

LDCs purchase natural gas using a number of different kinds of contractual arrangements, the terms of which can have a significant impact on the ultimate cost of the gas paid by customers. Supply contracts can be made for different durations: long-term contracts stretching for a year or longer, mid-term contracts of more than a month but less than a year, or monthly or even daily periods. For their peak-month supplies, LDCs tend to rely primarily on mid-term contracts (one to 12 months), though more than half of the respondents to the AGA survey reported using long-term contracts for as much as 50% of their peak month supply.

In addition to differing timeframes, gas supply contracts can include one of several different pricing mechanisms, including a fixed price for the contract's duration, a weekly average price, a daily price, a first-of-the-month index, a three-day average, or the price of futures contracts traded on the New York Mercantile Exchange (NYMEX). The AGA survey showed that 20 of 22 LDC survey respondents used first-of-the-month pricing for their long-term contracts, and only a few used other pricing mechanisms. For mid-term contracts, first-of-the-month pricing was still the most common, though fixed, daily, and NYMEX-based pricing mechanisms also were used.

In addition to their physical supply contracts, LDCs often will use financial derivatives to hedge the cost of gas for their customers. These financial instruments—futures, options, and swaps—are available through an organized, regulated exchange (such as NYMEX), as well as in the "over-the-counter" market, from trading desks at various commercial banks, investment banks, marketers, and other natural gas intermediaries.

How an LDC purchases its supply, and whether it uses financial futures to hedge risk, often is heavily influenced by the type of regulatory regime under which the LDC operates. LDCs must convince regulators that their gas purchases were prudent and reasonable, or they may not be granted full reimbursement by the commission.

Recovering gas supply costs

LDCs supply natural gas to customers who have not arranged to buy gas from an independent marketer. While recovering the cost of gas appears simple enough in theory, in practice it can be quite complicated. Gas prices fluctuate from day to day and from month to month, whereas rates may be set for years into the future. This timing mismatch creates a risk that utilities may not fully recover the cost of gas purchased if what they collect for gas supplied is insufficient to cover their costs. Even more worrisome is the fact that regulators may not allow utilities to collect the full cost of gas if their initial cost estimates prove unreliable.

States have widely varying procedures in place for LDCs to recover the cost of gas supplied to customers. Some have automatic pass-through mechanisms linking customer prices to gas price indices that change prices monthly. In other states, however, LDCs must wait until the season is over and then apply to regulators to recoup undercharges. They then run the risk that regulators will not permit full recovery of their gas procurement costs in the next rate case. During times of high gas prices, even delayed recovery of gas supply costs can hurt an LDC's liquidity, forcing it to increase its borrowings (thus raising its interest expense); in extreme cases, this can hurt its credit rating.

Transportation

The physical properties of natural gas make it difficult to transport by any means except a dedicated pipeline. While a few LDCs have their own gas production that can be used to supply customers, long-distance pipelines are the only realistic way for most LDCs to secure enough supply to satisfy full customer demand.

Until the mid-1980s, LDCs purchased their gas directly from the transmission pipeline serving their area, paying a single price for the gas together with any additional charges for transportation and storage. While this arrangement worked well in assuring stability of supply, it was inefficient, as it required LDCs to contract enough gas to meet their peak demand levels throughout the year, even if the pipeline capacity went unused. These costs were passed along to gas customers.

The regulatory reforms that began in 1984 and were completed in 1992 allowed LDCs to shop around for their gas from producers, instead of being forced to buy from pipeline companies. They also were permitted to sell unused pipeline transportation capacity to others in what is known as a "capacity release market." As a result, LDCs now use a range of options to meet their transportation requirements, including gas released from storage, short-term firm transportation rights, interruptible transportation, released capacity, and "gray market" services (capacity repackaged with supply or other services by LDCs or independent marketers).

The AGA's survey found that most LDCs still used firm transportation for the majority of their peak month supply: 16 of 31 responding companies said that they buy between 50% and 75% of their peak month supplies via firm transportation. Only two of 30 companies reported purchasing peak month supplies via interruptible transportation, and then for less than 25% of their supply.

Storage

Natural gas is bulky and expensive to transport. Because transportation capacity to large demand centers cannot be increased on short notice, gas storage facilities play an important role in LDCs' efforts to secure supply. In particular, storage is most important during times of peak demand, when demand exceeds pipeline transmission capacity. About 20% of the gas used during winter months comes from storage, according to the AGA, while 50% or more of the gas burned on an extremely cold day may come from storage.

For these reasons, gas storage facilities have become extremely important to LDCs. Gas can be stored in one of several types of facilities, including salt caverns, disused mines, aquifers, hard rock caverns, or depleted gas reservoirs. LNG also can be stored in specially constructed insulated containers near regasification terminals. Small volumes of compressed gas can be stored in tanks commonly referred to as gas holders. Such storage facilities are used for shipments to or from areas where pipelines are not available.

Owning or controlling storage reservoirs allows LDCs to guarantee future deliveries and to actively manage inventories against fluctuating natural gas prices. Control or ownership also reduces the reliance on transmission pipeline capacity and limits the potential effect of a pipeline outage. Inventory can be managed by purchasing gas during times of weak demand, when prices are low, and storing it for use during periods of peak consumption. Storage capacity also can be leased to third parties, providing an additional source of revenue.

Because US natural gas consumption peaks in the winter, producers store gas during the months when temperatures and demand are moderate (April through October) and withdraw gas during the heating season (November through March). The US government, commodity traders, and LDCs track storage levels extremely closely to determine demand levels, supply availability, and likely future price trends.

Storage facilities may be classified as either seasonal supply reservoirs or high-deliverability sites. Seasonal supply sites are designed to be filled during the 214-day non–heating season and to be drawn down slowly during the 151-day heating season. In comparison, high-deliverability sites are situated to provide a rapid drawdown or rebuilding of inventory to respond to such needs as volatile peaking demands, emergency backup, and/or system load balancing. High-deliverability sites can be drawn down in 20 days or less and refilled in 40 days or less.

Gas storage capacity is an important tool for LDCs to manage price volatility. A report by the FERC in October 2004 said that improving storage infrastructure was the best way to manage volatile prices. The FERC concluded that existing storage capacity was adequate, but that the industry would benefit from additional capacity because it would help smooth price spikes by increasing the amount of supply close to demand centers. The further a demand center is removed from supply sources, the more that storage will help, the FERC report concluded.

END MARKETS

Residential, commercial, and industrial customers, as well as electric power plants, use natural gas for a variety of purposes, including heat, power generation, and as the raw material for products such as chemicals and fertilizer. Each group displays markedly different responses to changing weather patterns, price levels, and economic activity. Before the gas even reaches these customers, however, some is used for other purposes: 5.5% is used for lease and plant fuel in processing the gas and 2.7% is used for transportation. Thus, of the 23.2 Tcf of gas consumed in the US during 2008, 91.8% (or 21.3 Tcf) reached the end markets.

LDCs classify their customers as either firm or interruptible. Industrial customers, as well as some commercial customers, have the option of choosing firm gas supply, regardless of their level of demand, for a correspondingly higher price. For customers that can accommodate temporary interruptions or switch to alternative fuels, interruptible service and its corresponding price advantage may be preferable. Residential customers always receive firm service.

Electricity generation

In 2008, electric power generators were the largest class of natural gas customer, with relatively few customers accounting for about 31.3% of US gas delivered to consumers in 2008. Gas-fired power generation capacity has grown rapidly in the United States in recent years, for several reasons. Shorter construction times and lower capital investment requirements than other types of power plants made gas-fired power plants an attractive investment during a time of rising electricity prices. New combined cycle technology has increased the efficiency of gas-fired generation, and concern over the environmental impact of coal-fired and nuclear generation has encouraged more gas-fired plants.

Power generators are even more sensitive to changing natural gas prices than industrial users, operating only when electricity prices are high enough to make burning gas for power profitable. Gas consumption by power generators fell by almost 10% in 2003, when rising gas prices made it less profitable to burn as a fuel for generating power. However, generator consumption of natural gas rose in 2004 by 6.4%, in 2005 by 7.4%, in 2006 by 6.0% and in 2007 by 10%—even though prices were still high—due both to increasing power prices and new generation fueled by gas. However, in 2008, consumption fell by 3.1%, reflecting a cooler summer than in 2007. In 2007, the EIA said that gas-fueled power plant additions provided an additional 4.5 gigawatts (GW) of net power capacity. However, for the first time ever, new non-hydro renewable capacity increased more than any other type, adding 8.7 GW of capacity in 2007.

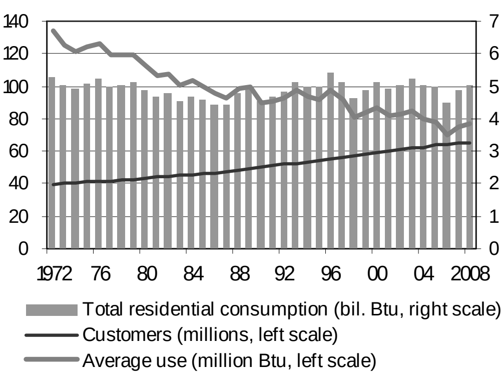
Several factors other than price can affect short-term natural gas demand patterns for electric power generators. Weather-related events—as well as other developments, such as plant outages, that can raise or lower electricity prices—can cause sudden spikes in gas demand. The rising share of gas demand from electric power producers has created a new "summer peak" in demand, as gas-fired power generators increase their use during periods of hot weather to meet higher power demand for air conditioning.

The industrial market

Industrial consumers were a very close second largest source of demand for natural gas in 2008, accounting for about 31.1% of the total consumer volumes. In 2007 (latest available data), about 195,000 different industrial customers used natural gas as fuel to produce heat and steam, or as feedstock for chemicals and fertilizer. Chemical makers are the largest group of industrial gas users, accounting for about 10% of total US demand. Makers of paper, steel, and building materials are also large gas consumers.

Consumption by industrial users tends to be more sensitive than commercial or residential demand to changes in economic activity and price, because industrial customers have greater ability—and incentive—to alter their consumption as market forces dictate. Because demand per customer is much larger than it is for commercial or residential users, one industrial customer's decision will have a larger impact on total demand.

THE US RESIDENTIAL NATURAL GAS MARKET



Btu-British thermal units.
Source: US Energy Information Administration.

The residential market

Residential gas users, numbering about 65.1 million in 2008, accounted for about 22.8% of gas volumes delivered to customers. While residential customers are more expensive to supply as a result of the billing and customer service infrastructure required, they pay substantially higher prices than industrial or commercial customers and thus supply the lion's share of utility profits. In 2008, the yearly average for residential natural gas prices was about $13.68 per thousand cubic feet (Mcf)—14.1% higher than commercial prices ($11.99/Mcf), 42.4% above average industrial prices ($9.61/Mcf), and 46.3% above prices paid by electric power generators ($9.35/Mcf).

Approximately two-thirds of residential natural gas demand is for space heating, though that demand is confined mainly to winter months. Gas also is used to power home appliances such as water heaters, stoves, clothes dryers, and fireplaces. Although overall levels of natural gas demand by residential customers rise and fall with the severity of winter weather—and also with other factors, such as population growth and housing trends—the use of natural gas per residential customer is in a long-term decline. Since 1978, natural gas demand per residential customer has exhibited a 1.5% annual compound average shrink rate, according to calculations using data from the EIA. However, since 1998, per customer residential demand has slowed its rate for shrinkage to just 0.6%, possibly reflecting slowing market penetration rates for energy efficient appliances. Demand is likely to continue to drop by about 0.5% each year through 2020, assuming normal weather patterns, due mainly to continuing market penetration of efficient gas furnaces and appliances.

The commercial market

Commercial customers comprise nonmanufacturing businesses such as hotels, restaurants, wholesalers, retailers, and other service-oriented businesses. Natural gas used by state and federal agencies for nonmanufacturing purposes is also counted as commercial demand. The commercial market, with about 5.3 million customers in 2007 (latest available data), is smaller than the industrial, residential, or power generation markets; it accounted for 14.7% of total consumer demand in 2008.

Gas demand is somewhat less seasonal for commercial customers than for residential customers. Slightly more than half of all commercially consumed gas is currently used for purposes of space heating, with the remainder used for water heating, cooking, and a variety of other purposes. The commercial customers' compound annual growth rate was 1.4% between 1987 and 2007; during the same period, however, per-customer usage fell 0.3% annually. More efficient space- and water-heating appliances accounted for most of the decline; gas customers switching to electricity for cooling purposes also contributed.

Other uses

Small amounts of natural gas (0.14% in 2008) are used as vehicle fuel and as a component of fuel cell technology. Many decades from now, these markets could become significant consumers of natural gas. The number of natural gas vehicles in use in the United States has been rising, helped by technological advances in natural gas–fired engines. Since 1998, the compound annual growth rate for other gas usage has been 12.4%. Natural gas vehicles may provide a bridge to the fuel cell vehicle of the future, which has the potential to create enormous demand for natural gas. Natural gas contains high concentrations of hydrogen and already is supported by a vast distribution system.

KEY INDUSTRY RATIOS AND STATISTICS

◆ **Heating and cooling degree days.** Natural gas is consumed in proportion to extremes in temperature. Residential, commercial, and industrial markets typically use gas for heating enclosed spaces (space heating). In the United States, the heating season generally is considered to last from November through March, though it's somewhat longer in the northern part of the country and somewhat shorter in the South.

Cooling degree days occur during the warm summer months when customers run air conditioning units. This measure also is gaining importance as a barometer of natural gas consumption because electric utilities are increasingly operating gas-fired power plants.

Space heating accounts for approximately two-thirds of residential gas demand and half of commercial use. Consequently, shifts in the relative severity of weather during the heating season affect year-to-year changes in natural gas consumption in these sectors.

When analysts make projections of future gas demand, they assume "normal" weather, quantified in terms of heating and/or cooling degree days. A degree day is a measure of the relative warmth or coldness of the air, based on how far the daily mean temperature falls above or below a reference temperature, usually 65 degrees Fahrenheit. For example, a day with a mean outdoor temperature of 35 degrees Fahrenheit would be counted as a 30-degree heating day. The National Oceanic and Atmospheric Administration (NOAA), an agency of the US Department of Commerce, calculates reference temperatures on a monthly basis. Given the variability of the weather, natural gas demand always will be subject to some unpredictable volatility.

◆ **Real gross domestic product (GDP).** Although weather is the main cause of swings in gas consumption, weather-normalized gas demand historically has tended to follow the overall economy. Average annual growth in US natural gas demand has typically run at a pace of slightly less than three-quarters of real GDP growth. Real GDP is the market value of the nation's output of goods and services, adjusted for inflation; it is reported quarterly by the Department of Commerce.

The economy affects all three sectors of the gas market. In the residential sector, the number of housing starts is influenced by economic conditions. For commercial and industrial customers, an increase in business activity translates into greater energy consumption, despite increasingly energy-efficient equipment. For an individual utility or energy merchant, demand growth depends heavily on economic trends within its geographic region. These can vary somewhat from GDP trends.

◆ **Housing starts.** The residential market offers the widest margins and the lion's share of profits for natural gas distributors. For this reason, housing starts—the number of residences on which construction has begun in a given period—are significant for the natural gas industry. These figures, reported as seasonally adjusted annualized rates (SAAR), are available from the Department of Commerce on a monthly basis.

The residential market accounted for almost two-thirds of natural gas utility profits. It is characterized by a larger number of customers who individually consume much less fuel than is the case in industrial and commercial markets. Accordingly, residential customers pay more on a per-unit basis than industrial and commercial customers do.

The most important factors contributing to changes in demand in the residential market are new housing, conversions from alternate fuel heating to natural gas, and weather. Growth in space heating installations is not the only benefit of a robust housing market. The gas industry also benefits from the increase in appliance shipments. However, appliance design improvements have reduced per-unit natural gas consumption over time.

◆ **Interest rates.** The regulated and capital-intensive nature of the utility industry makes a utility's financial performance very sensitive to the level of interest rates and available returns. Utility rates are determined by state regulatory agencies based on operating costs, capital investments, and the cost of capital. Changes in overall interest rates affect utility rates via the allowed cost of debt and the allowed return on equity (ROE). When interest rates drop substantially, the rates that utilities are allowed to charge are likely to be lowered as financing cost savings are passed on to customers.

Income-oriented investors are sensitive to interest rates when they evaluate a utility company's shares. If interest rates are rising, investors can receive comparable returns elsewhere. To invest in a utility, income-oriented investors look for a large dividend yield or consistently growing dividend distributions to compensate for the risk of owning stock versus a fixed-income security. The dividend tax cut of 2003 makes dividends more attractive relative to fixed-income securities and other investment alternatives.

HOW TO ANALYZE A NATURAL GAS COMPANY

The performance of natural gas companies depends heavily on the mix of their operations. The owners of local distribution companies (LDCs) typically have other operations—both regulated (long-distance pipelines and electricity distribution) and unregulated ("merchant energy" power generation assets and wholesale gas marketing desks). Each of these businesses has a unique competitive position, financial condition, and exposure to changing market prices and regulatory regimes.

The earnings streams from unregulated generation and trading businesses are much more volatile, as they can be subject to wild swings in commodity prices. Pipelines are more similar to LDCs, but they are more loosely regulated and subject to more competition. Analytical considerations for LDCs, merchant energy assets, and pipelines are described separately following.

LOCAL DISTRIBUTION COMPANIES

In analyzing an individual LDC, it is important to consider a number of issues related to energy markets and company management.

Competitive position

To assess where an LDC stands competitively, first compare the rates it charges its customers with those of neighboring utilities and the national average. Favorable comparisons are generally indicative of a company's focus on cost controls. Traditional utility regulation (versus "performance-based ratemaking") does not allow an LDC to profit from cost-savings initiatives associated with pass-through ratepayer expenses. However, low rates can engender healthy relationships with regulators and help fend off competitive threats.

Regulatory reforms have made it vital to track competitive threats. Independent gas marketers have proliferated, making inroads into the utilities' service areas by competing for large gas customers. Increasingly, interstate pipeline companies are trying to bypass the LDCs by distributing gas directly to large-volume industrial users.

Note how an LDC faces these challenges. Has it secured at-risk customers through long-term contracts or flexible pricing agreements? Does it offer bundled services? Has it formed its own marketing arm to compete directly with gas marketers? Has it obtained performance-based regulation (PBR) mechanisms that permit efficiencies to be shared between shareholders and ratepayers?

Location and customer mix

Demand growth occurs in several ways: an increase in customers in a company's service area, increased consumption by existing customers, or both. An expanding economy and above-average population growth within an LDC's service territory are generally favorable characteristics.

Customer growth does not necessarily translate into greater total volumes delivered, however, because the rate of gas consumption per household has been declining for years due to energy-efficient appliances. If state regulatory commissions do not compensate LDCs appropriately for declining consumption patterns, it could slow the capital investment a company needs to make to provide gas utility connections to a growing population.

It is important to note the proportion of an LDC's residential customers to total customers in a service territory. A greater percentage of residential customers will yield a more stable and predictable revenue stream. Industrial customers and electric utilities that use gas tend to be more price-sensitive. It is also preferable for an LDC to limit the percentage of its business that comes from any single large customer. If one customer accounts for a significant portion of a utility's sales, the analysis must focus on that customer's stability and the utility's competitive position in retaining its business.

While a greater proportion of residential customers generally confers stability, excessive residential exposure has its drawbacks. Residential customers are "full-service" customers, meaning that the LDC must always fulfill all customer demand, however great or small. This creates both inventory management and commodity price risks for the LDC. If too much gas is left over after the heating season, the LDC must store or sell excess supplies, which can reduce earnings.

A further complication is that residential demand tends to be greatest when gas prices are high (during a very cold winter, for example). State public utility commissions often subject the commodity pass-through expenses incurred by LDCs to "prudency" reviews. If an LDC's gas procurement strategy is found to be insufficiently judicious, the company can be required to absorb some commodity costs. In addition, residential bad-debt expense tends to increase when higher commodity prices and increased consumption drive up monthly bills. Analysts can gauge an LDC's susceptibility to inventory management and commodity price risks by evaluating its gas procurement and price hedging strategy, its relationship with regulators, and its management of bad debt.

The penetration rate for residential gas heating in a utility's service territory is important. For example, in many older communities in the Northeast, the conversion of customers from oil to gas heating has boosted revenue growth.

Regulatory environment

LDCs are subject to rate of return regulations controlled by state utility commissions. Thus, it is important to study trends at the regulatory commission(s) with jurisdiction over an LDC's service territories. Compare authorized rates of return with the rates allowed industry peers. Are there automatic "true-up" mechanisms that allow pension, bad debt, and other costs to be passed through automatically to ratepayers? When will the next rate filing take place? Has performance-based regulation been approved, or could it be approved by the state utility commission?

Timing requests for rate reviews are important. Even if an LDC seeks higher rates based on reasonable capital expenditures, if interest rates are low (affecting the allowed return on equity) and commodity costs are high (affecting ratepayer pocketbooks), regulators may be unwilling to grant relief.

For diversified utility companies, regulatory issues affecting other utility operations, such as electric or water, must be considered. The impact that the 2000–01 power crisis had on California's diversified utilities exemplifies this.

Gas supply and demand

To determine its need for gas supply and transportation capacity, an LDC must decide how much gas to contract on a firm basis. Conversely, how much should it buy on the spot market, and how much capacity should be interruptible? How much storage capacity does it need to meet demand on peak days?

A well-run LDC is likely to obtain gas from various producers or marketers, from different gas basins in the United States and Canada, and/or from different pipeline routes. It generally will have firm purchase contracts—preferably for an intermediate term—with minimal take-or-pay provisions (which require it to purchase specified quantities of natural gas whether needed or not). A distribution company must carefully manage its storage requirements, as well as its gas supply and transportation arrangements. If it is not successful in these regards, an LDC faces a greater risk of hindsight prudence reviews by regulators and potential disallowance of its purchased gas and transportation costs.

Storage

An LDC's access to storage capacity helps it control both the supply and cost of its gas. Storage helps it to meet increased demand on peak days and allows it to purchase gas during off-season months, when prices are lower.

An LDC that owns storage facilities can lease any unneeded capacity to others. Conversely, an LDC that does not own storage facilities must continually ask how much gas it needs and how much it should pay for the gas. The problems associated with not owning storage facilities can lead to unstable costs. The creation of storage operations represents a major capital commitment. Thus, it is not surprising that larger gas utilities, with more customers and volume demand, tend to take greater advantage of the storage option.

Unregulated activities

To remain viable in a market-driven environment, an LDC's management team must develop strategies to address competitive pressures. These strategies could involve the introduction of wholesale trading and marketing operations, investment in competitive retail distribution, or the development of natural gas exploration and production operations.

Every foray into unregulated activities carries greater potential for risks and rewards than do regulated utility operations. The risks are even higher, however, when utility managers move into business lines in which they have little experience. Investments in unregulated operations may put undue strains on a utility's credit and could dissuade state regulators from approving mergers, new performance-based regulations, or other utility initiatives.

Looking at the income statement

Due to the vagaries of weather and the constraints of regulation, two common profitability measures—net income and earnings per share (EPS)—are not as important in analyzing a utility as in analyzing some other companies. For a better gauge of value and performance, analysts look at how a company manages its financial resources and at its overall health. The three most important items to examine in analyzing a gas distribution company's income statement are net revenues, operating expenses, and interest expense.

◆ **Net revenues.** For utilities, growth in net revenue (revenues, less fuel expense) is somewhat predictable because of the regulatory constraints on rates. Nonetheless, past sales trends should be evaluated. Did growth come from a rate increase? An improving economy? Rising weather-related demand? Expectations for the future also should be considered.

◆ **Operating expenses.** As competition among gas utilities grows, cost-containment and productivity efforts are crucial to earnings performance. Because fuel costs fluctuate widely, the analyst should pay close attention to nonfuel operating and maintenance costs. Changes in expenses from one period to the next should be noted, along with whether expenses are trending up or down as a percentage of net revenues. The number of customers served per employee is an effective means of tracking trends in operating efficiency.

◆ **Interest expense.** The utility industry is extremely capital-intensive, so interest payments are a utility's most significant nonoperating expense. Analysts calculate the pretax interest coverage ratio, which indicates how much of the company's pretax income is needed to meet interest payments. This measure becomes increasingly important as a company engages in greater levels of unregulated operations, due to the uncertainty of earnings derived from such activities.

Evaluating the balance sheet

When looking at an LDC's balance sheet, pay close attention to the company's capitalization ratio: long-term debt as a percentage of total capital.

Because public utilities require a substantial investment in long-term assets, they traditionally have had significantly more long-term debt on their balance sheets than companies in other industries. Investors usually have accepted these higher debt levels because of the regulated nature of the industry (which ensures income that largely covers the cost of the debt) and utilities' relatively stable earnings (which consistently provided sufficient funds to cover interest payments). Greater exposure to unregulated activities, however, increases the risk associated with heavy indebtedness.

It is important to compare an LDC's capitalization ratio with its own historic levels, as well as with those of its peers. These findings then should be put in the context of changes in the LDC's mix of regulated and unregulated operations.

Assessing cash flow

A review of cash flow trends often can give clues to a utility's health. The company should generate sufficient cash to meet all ongoing expenses. It also needs cash to fund business expansion and, in most cases, to pay dividends.

A firm's ability to tap capital markets on an ongoing basis must be considered. Therefore, it is important to look at the company's cash flow relative to its debt. A positive and growing cash flow lets the utility finance more of its expansion internally and reduces its dependence on the capital markets.

PERFORMANCE AND VALUATION MEASURES

These measures include return on equity, return on assets, the ratio of earnings to fixed charges, the price-to-book ratio, the price/earnings ratio, and dividend payments.

◆ **Return on equity (ROE).** This performance measure reveals how well a company invests its capital. It is calculated by dividing net income (less preferred dividend requirements) by average shareholders' equity.

◆ **Return on assets (ROA).** This performance measure shows how efficiently a company uses its assets. It is calculated by dividing utility operating income by total plant assets less accumulated depreciation.

◆ **The ratio of earnings to fixed charges.** This calculation reveals a company's ability to cover fixed charges (amortization and interest expense) with pretax earnings.

◆ **Price-to-book (P/B) ratio.** Comparing the market price of the company's shares with its book value indicates how much investors are willing to pay for the company's assets. LDCs usually do not have high levels of goodwill. In selected cases, though, growth-oriented LDCs that have made significant acquisitions may appear to have disproportionately higher book values (and lower P/B multiples) than their peers, due to their goodwill balances.

◆ **Price/earnings (P/E) ratio.** Another way to evaluate the current market price of the utility's shares is to look at the P/E ratio. Compare company's current P/E (based on both trailing and future estimated earnings) with that of its industry peers and with its own historical range. Given their lower EPS growth rates, utility stocks normally trade at a discount to the overall market P/E. When making comparisons of companies within the utility sector, investors tend to pay a higher P/E for, and accept a lower dividend yield from, shares of a utility company with above-average earnings growth potential.

A useful related measure is the P/E to growth (PEG) ratio: the stock's P/E, divided by the present (or future) earnings growth rate. Is the PEG ratio higher than, lower than, or equal to the industry overall? How does it compare with the company's historical PEG ratios?

◆ **Dividend payments.** In general, most utility shareholders do not view a utility stock as a high-growth investment; rather, they are most interested in the stock's total return potential—its share appreciation combined with its dividend yield. Dividend yield is a larger component of total expected return on a utility stock than for the typical industrial company stock. Consequently, a utility's ability to pay a dividend—and to provide steady dividend increases—is of paramount importance. To determine if a dividend is secure, the analyst should check the payout ratio (the annual dividend divided by earnings per share). A utility that is paying out too high a percentage of its earnings may need to cut future payments if earnings weaken.

When looking at an individual company, it is important to determine the utility's dividend policy. As many utilities began investing in unregulated activities, they sought to reduce their payout ratios by either immediately cutting the dividend or holding it constant as earnings rose over time. In cases where the dividend payout ratio is falling, investors must analyze the potential returns from growth-oriented unregulated investments versus the value of the forgone dividend stream.

MERCHANT ENERGY OPERATIONS

Unregulated power generation, wholesale gas marketing, and other merchant energy operations need a stronger balance sheet than LDC businesses. Energy marketing and trading activities demand high levels of financial security in order to assure both trading counterparties and credit rating agencies that a company can survive volatile swings in the energy markets. In contrast to regulated utilities, the value of unregulated assets owned by energy merchants can fluctuate wildly, exposing otherwise healthy balance sheets to asset write-downs during bad times. To safeguard against such volatility, many companies have attempted to lock in favorable prices with long-term customer contracts.

An analyst must evaluate the proportion of merchant energy business that is exposed to short-term market risk and the ability of the company's liquidity and balance sheet to persevere through industry downturns. Furthermore, one also must evaluate the credit profile of a company's major contractual counterparties. Hedging unregulated assets through long-term contracts with weak counterparties may provide very limited protection against a cyclical downturn.

The volatility of merchant energy operations has cast a light on company growth initiatives as well. Business plans that require years of capital spending far in excess of operating cash flows can become a liability during an industry downturn, when financial liquidity takes on increased importance. An analyst must evaluate the quality of a company's new merchant energy investments and the flexibility of capital spending commitments.

It is important to evaluate the energy merchant's risk management control. This concept covers asset management, trading limits and monitoring, and debt management. Only recently have merchant energy managers begun to develop consistent industrywide reporting practices. Disclosure and transparency have increased with the backlash against the sector in recent periods. An analyst must make use of these disclosures (including value-at-risk measures, proportion of hedges, credit exposure, debt maturity schedules, and the like) to evaluate the true risk/reward opportunities presented by each unregulated merchant energy business.

PIPELINES

Interstate pipelines have both utility and merchant energy characteristics. They are similar to monopoly utilities in that they require significant capital expenditures, involve a permitting process, and are subject to price controls. However, an interstate pipeline's service territory can be expanded through new permitting and construction, whereas this is not usually the case for LDCs. Pipelines are also subject to competition from other pipelines that are built close enough to contend for institutional customers.

Pipelines differ from LDCs in that their business generally relies on a limited number of large institutional customers (including wholesale marketers, exploration and production companies, LDCs, and large industrial companies). Such high customer concentration increases the risks associated with bad debt expense. When evaluating a pipeline company, an analyst must investigate demand and supply growth along a pipeline's footprint, opportunities for pipeline expansion, applications for competitive pipeline developments, and the growth prospects and credit quality of shippers along the pipeline's system.

Pipeline capacity utilization is affected by the location of natural gas supply sources and shifts in consumption patterns. A change in source requires new pipelines to transmit gas from growing production centers (such as the Rockies). The increasing use of LNG imported via tanker also will affect the need for and utilization of pipeline assets.

The demand side of the equation is subject to potential secular shifts. For example, growth in the number of gas-fired electric generating plants has had a major impact on geographical demand patterns. The analyst must be aware of longer-term supply and demand trends that could increase or decrease the value of pipeline assets.

Many pipeline companies historically have engaged in various unregulated merchant energy activities through subsidiary operations. Thus, the analyst must be careful not to assume that a company has a low-risk profile just because it owns substantial regulated pipeline assets.

A number of pure-play pipeline businesses are owned by master limited partnerships (MLPs). MLPs trade on exchanges just like common stocks, but the businesses avoid income taxation by paying out nearly all free cash flows to shareholders. These income-oriented investments generally trade based on their yield, distribution growth potential, and volatility of cash flows.

Because MLPs cannot use operating cash flows for growth-oriented capital expenditures, they depend on the ability to continuously raise fresh debt and equity capital to fund new investment. Unlike other pipeline companies, MLPs generally cannot be held by pension funds due to current tax obligations generated from their partnership structure. Accordingly, shares of publicly traded MLPs generally are held by smaller retail investors.

The general partners (GPs) for MLPs often have performance participation awards that provide the GPs with larger and larger interests in MLP distributions as the dividend is raised. An analyst needs to evaluate an MLP's capacity to raise distributions in light of growth opportunities, access to capital markets, and GP performance participation awards. ■

INDUSTRY REFERENCES

PERIODICALS

Inside FERC
Platts Retail Energy
Gas Daily
http://www.platts.com
The first two are weekly newsletters providing an authoritative source of information on the workings of the Federal Energy Regulatory Commission (FERC) and its impact on the regulated industry, and industry news, respectively. The third is a daily that provides detailed coverage of natural gas prices. (Platts, like Standard & Poor's, is part of The McGraw-Hill Cos. Inc.)

Natural Gas Week
http://www.energyintel.com
Weekly newsletter; covers industry news.

Platts Gas Daily
http://www.platts.com/products.shtml
Daily newsletter; covers gas industry news.

Public Utilities Fortnightly
http://www.pur.com
Biweekly magazine; covers the electric and gas utility industries.

The Waterborne LNG Report
http://www.waterborneIng.com
Weekly report; gives data and estimates of liquefied natural gas (LNG) import and export volumes to the US and Europe.

TRADE ASSOCIATIONS

American Gas Association (AGA)
http://www.aga.org
Natural gas industry association that conducts technical research, compiles authoritative statistics, and helps create standards for industry equipment and products.

American Public Gas Association (APGA)
http://www.apga.org
Represents municipal gas systems.

Center for Liquefied Natural Gas
http://www.lngfacts.org
Represents LNG asset owners and operators, gas transporters, and natural gas end users.

Gas Technology Institute (GTI)
http://www.gastechnology.org
Not-for-profit technology organization that conducts research, development, and commercialization programs for the natural gas industry.

Industrial Energy Consumers of America
http://www.ieca-us.com
Represents energy-intensive manufacturing industries.

Interstate Natural Gas Association of America (INGAA)
http://www.ingaa.org
Advocates regulatory and legislative positions for the North American natural gas pipeline industry.

National Association of Regulatory Utility Commissioners (NARUC)
http://www.naruc.org
Represents individual states' viewpoints on regulation.

The Natural Gas Supply Association
http://www.ngsa.org
Represents US natural gas producers.

CONSULTANTS

Baker Hughes Inc.
http://www.bakerhughes.com
Firm providing various oil and gas industry consulting services to its clients. It is also considered to be the authority on rig count data and publishes weekly and monthly rig count information.

Global Insight Inc.
http://www.globalinsight.com
Research firm providing economic data, forecasts, analysis, and consulting. Among its many publications is the *Monthly Natural Gas Price Outlook*.

Platts/The McGraw-Hill Cos. Inc.
http://www.platts.com
Strategic energy information, consulting, and publishing firm.

SNL Financial
http://www.SNL.com
Research firm providing regulatory, financial, market, and M&A data on several industries, including energy.

GOVERNMENTAL AND REGULATORY BODIES

Energy Information Administration (EIA)
http://www.eia.doe.gov
Agency within the US Department of Energy; supplies publications and statistics on the natural gas industry, as well as on power, coal, and a variety of other energy areas, including supply, consumption, and transportation issues.

Federal Energy Regulatory Commission (FERC)
http://www.ferc.gov
Agency within the US Department of Energy that exercises regulatory control over the electric power and natural gas industries. It also regulates producer sales of natural gas in interstate commerce and, for each of several categories of natural gas, establishes uniform ceiling prices that apply to all sales nationwide.

Federal Trade Commission (FTC)
http://www.ftc.gov
Independent agency reporting to the US Congress, the FTC is charged with maintaining competition and safeguarding consumers' interests. Reviews proposed mergers involving electric and gas utility companies; may analyze regulatory or legislative proposals affecting energy market competition or the efficiency of resource allocation.

US Department of Energy (DOE)
http://www.energy.gov
Federal science and technology agency whose research supports the nation's energy security, national security, and environmental quality. Introduced to the US Cabinet in 1977, the DOE includes the Office of the Secretary of Energy, the FERC, and other agencies.

National Energy Board (NEB)
http:// www.neb-one.gc.ca
Independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries in Canada.

COMPARATIVE COMPANY ANALYSIS — NATURAL GAS DISTRIBUTION

Operating Revenues

			Million $							CAGR (%)			Index Basis (1998 = 100)				
Ticker	Company	Yr. End	2008	2007	2006	2005	2004	2003	1998	10-Yr.	5-Yr.	1-Yr.	2008	2007	2006	2005	2004
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	2,800.0 F	2,494.0 F	2,621.0 F	2,718.0 F	1,832.0 A,F	983.7 C,F	1,338.6	7.7	23.3	12.3	209	186	196	203	137
ATO	† ATMOS ENERGY CORP	SEP	7,221.3 F	5,898.4 F	6,152.4 F	4,973.3 A,F	2,920.0 F	2,799.9 C,F	848.2 F	23.9	20.9	22.4	851	695	725	586	344
EGN	† ENERGEN CORP	DEC	1,568.9 F	1,435.1 D,F	1,338.5 D,F	1,128.4 D,F	937.4 D,F	842.2 D,F	502.6 F	12.1	13.2	9.3	312	286	266	224	186
EQT	[] EQT CORP	DEC	1,576.5 F	1,361.4 F	1,267.9 D,F	1,253.7 D,F	1,191.6 F	1,047.3 A,C	882.6 D,F	6.0	8.5	15.8	179	154	144	142	135
LG	§ LACLEDE GROUP INC	SEP	2,209.0 D,F	2,021.6 F	1,997.6 A,F	1,597.0 F	1,250.3 F	1,050.3 F	547.2	15.0	16.0	9.3	404	369	365	292	228
NFG	† NATIONAL FUEL GAS CO	SEP	2,400.4 F	2,039.6 D,F	2,311.7 F	1,923.5 D,F	2,031.4 F	2,035.5 F	1,248.0	6.8	3.4	17.7	192	163	185	154	163
NJR	§ NEW JERSEY RESOURCES CORP	SEP	3,816.2 F	3,021.8 F	3,299.6 F	3,138.2 F	2,533.6 F	2,544.4 F	710.3 F	18.3	8.4	26.3	537	425	465	442	357
GAS	[] NICOR INC	DEC	3,776.6 F	3,176.3 F	2,960.0 F	3,357.8 F	2,739.7 F	2,662.7 C,F	1,465.1 F	9.9	7.2	18.9	258	217	202	229	187
NWN	§ NORTHWEST NATURAL GAS CO	DEC	1,037.9 F	1,033.2 F	1,013.2 F	910.5 F	707.6 F	611.3 F	416.7 F	9.6	11.2	0.5	249	248	243	219	170
OKE	† ONEOK INC	DEC	16,157.4 F	13,477.4 F	11,896.1 D,F	12,676.2 D,F	5,988.1 F	2,999.0 C,D	1,835.4 A,F	24.3	40.0	19.9	880	734	648	691	326
PNY	§ PIEDMONT NATURAL GAS CO	OCT	2,089.1	1,711.3	1,924.6	1,761.1	1,529.7	1,220.8 A	765.3	10.6	11.3	22.1	273	224	251	230	200
STR	[] QUESTAR CORP	DEC	3,465.1	2,726.6	2,835.6	2,724.9	1,901.4	1,463.2	906.3 A	14.4	18.8	27.1	382	301	313	301	210
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	962.0 D,F	956.4 D,F	931.4 D,F	921.0 D,F	819.1 D,F	696.8 C,D	450.2 D,F	7.9	6.7	0.6	214	212	207	205	182
SWX	§ SOUTHWEST GAS CORP	DEC	2,144.7 F	2,152.1 F	2,024.8 F	1,714.3 F	1,477.1 F	1,231.0 F	917.3 F	8.9	11.7	(0.3)	234	235	221	187	161
UGI	† UGI CORP	SEP	6,648.2 F	5,476.9 F	5,221.0 A,F	4,888.7 F	3,784.7 F	3,026.1 F	1,439.7 F	16.5	17.0	21.4	462	380	363	340	263
WGL	† WGL HOLDINGS INC	SEP	2,628.2 F	2,646.0 F	2,637.9 D,F	1,379.4	1,267.9	1,301.1	1,040.6	9.7	15.1	(0.7)	253	254	253	133	122
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	3,681.7 F	3,437.6 D,F	3,359.4 D,F	3,279.6 D,F	2,958.7 D,F	3,128.2 C,D	2,130.9 F	5.6	3.3	7.1	173	161	158	154	139
AEE	[] AMEREN CORP	DEC	7,839.0	7,546.0	6,880.0 A	6,780.0 C,F	5,160.0 A,F	4,593.0 A,C	3,318.2 F	9.0	11.3	3.9	236	227	207	204	156
AVA	§ AVISTA CORP	DEC	1,676.8 A,F	1,417.8 F	1,506.3 F	1,359.6 F	1,151.6 C,F	1,123.4 C,D	3,684.0 F	(7.6)	8.3	18.3	46	38	41	37	31
BKH	† BLACK HILLS CORP	DEC	1,005.8 A,C	695.9 D,F	656.9 A,C	1,391.6 A,C	1,121.7 D,F	1,136.1 C,D	679.3 F	4.0	(2.4)	44.5	148	102	97	205	165
CNP	[] CENTERPOINT ENERGY INC	DEC	11,322.0 F	9,623.0 F	9,319.0 F	9,722.0 D,F	8,510.4 D,F	9,760.1 C,D	11,488.5 F	(0.1)	3.0	17.7	99	84	81	85	74
CHG	§ CH ENERGY GROUP INC	DEC	1,332.9 F	1,196.8 F	993.4 F	972.5 F	791.5 F	806.7 F	503.5	10.2	10.6	11.4	265	238	197	193	157
CMS	[] CMS ENERGY CORP	DEC	6,821.0 F	6,464.0 D,F	6,810.0 D,F	6,288.0 D,F	5,472.0 C,D	5,513.0 C,D	5,141.0 F	2.9	4.3	5.5	133	126	132	122	106
ED	[] CONSOLIDATED EDISON INC	DEC	13,583.0 F	13,120.0 D,F	12,137.0 D,F	11,690.0 D,F	9,882.0 D,F	9,827.0 C,F	7,093.0 F	6.7	6.7	3.5	191	185	171	165	139
D	[] DOMINION RESOURCES INC	DEC	16,290.0 D,F	15,674.0 D,F	16,482.0 D,F	18,041.0 D,F	13,972.0 D,F	12,078.0 C,D	6,086.2 F	10.3	6.2	3.9	268	258	271	296	230
DTE	[] DTE ENERGY CO	DEC	9,329.0 D,F	8,506.0 D,F	9,022.0 C,D	9,022.0 D,F	7,114.0 D,F	7,041.0 C,D	4,221.0 F	8.3	5.8	9.7	221	202	214	214	169
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	14,047.8 D,F	10,292.4 A,C	6,890.7 D,F	6,962.7 C,F	4,890.6 D,F	4,321.3 C,D	1,063.7 F	29.4	26.6	36.5	1,321	968	648	655	460
MDU	† MDU RESOURCES GROUP INC	DEC	5,003.3 F	4,247.9 D,F	4,070.7 D,F	3,455.4 F	2,719.3 F	2,352.2 C,F	896.6 A,F	18.8	16.3	17.8	558	474	454	385	303
NI	[] NISOURCE INC	DEC	8,874.2 D,F	7,973.3 D,F	7,490.0 D,F	7,899.1 D,F	6,666.2 D,F	6,246.6 D,F	2,932.8 F	11.7	7.3	11.3	303	272	255	269	227
NST	† NSTAR	DEC	3,345.4 F	3,261.8 F	3,577.7 F	3,243.1 F	2,954.3 F	2,914.1 F	1,622.5	7.5	2.8	2.6	206	201	221	200	182
OGE	† OGE ENERGY CORP	DEC	4,070.7 F	3,797.6 F	4,005.6 D,F	5,948.2 D,F	4,926.6 D,F	3,779.0 D,F	1,617.7 F	9.7	1.5	7.2	252	235	248	368	305
PCG	[] PG&E CORP	DEC	14,628.0 D	13,237.0	12,539.0	11,703.0 D	11,080.0 D	10,435.0 C,D	19,942.0 F	(3.1)	7.0	10.5	73	66	63	59	56
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	13,807.0 D,F	12,853.0 D,F	12,164.0 D,F	12,430.0 D,F	10,996.0 D,F	11,116.0 D,F	5,931.0 F	8.8	4.4	7.4	233	217	205	210	185
SCG	[] SCANA CORP	DEC	5,319.0 F	4,621.0 F	4,563.0 C,F	4,777.0 F	3,885.0 F	3,416.0 F	1,632.0	12.5	9.3	15.1	326	283	280	293	238
SRE	[] SEMPRA ENERGY	DEC	10,758.0 F	11,438.0 D,F	11,761.0 D,F	11,737.0 D,F	9,410.0 D,F	7,887.0 C,F	5,481.0 F	7.0	6.4	(5.9)	196	209	215	214	172
TE	[] TECO ENERGY INC	DEC	3,375.3 F	3,536.1 D,F	3,448.1 D,F	3,010.1 D,F	2,669.1 D,F	2,740.0 C,D	1,958.1 D,F	5.6	4.3	(4.5)	172	181	176	154	136
VVC	† VECTREN CORP	DEC	2,484.7 F	2,281.9 F	2,041.6 A,F	2,028.0 F	1,689.8 F	1,587.7 F	466.4 F	18.2	9.4	8.9	533	489	438	435	362
WEC	[] WISCONSIN ENERGY CORP	DEC	4,431.0 F	4,237.8 D,F	3,996.4 D,F	3,815.5 D,F	3,431.1 D,F	4,054.3 F	1,980.0 A	8.4	1.8	4.6	224	214	202	193	173
XEL	[] XCEL ENERGY INC	DEC	11,203.2 D,F	10,034.2 D,F	9,840.3 D,F	9,625.5 D,F	8,345.3 D,F	7,937.5 D,F	2,819.2	14.8	7.1	11.7	397	356	349	341	296
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AWR	§ AMERICAN STATES WATER CO	DEC	318.7	301.4	268.6	236.2	228.0	212.7	148.1	8.0	8.4	5.8	215	204	181	160	154
WTR	† AQUA AMERICA INC	DEC	627.0	602.5	533.5	496.8	442.0 A	367.2 A	151.0	15.3	11.3	4.1	415	399	353	329	293
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	7,041.7 A	8,934.3 A	6,453.8 D	5,253.9	4,243.8 A,C	4,145.3 D	11,205.1 D,F	(4.5)	11.2	(21.2)	63	80	58	47	38

Note: Data as originally reported. CAGR-Compound annual growth rate. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
**Not calculated; data for base year or end year not available. A - This year's data reflect an acquisition or merger. B - This year's data reflect a major merger resulting in the formation of a new company. C - This year's data reflect an accounting change.
D - Data exclude discontinued operations. E - Includes excise taxes. F - Includes other (nonoperating) income. G - Includes sale of leased depts. H - Some or all data are not available, due to a fiscal year change.

Net Income

Ticker	Company	Yr. End	Million $ 2008	2007	2006	2005	2004	2003	1998	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (1998 = 100) 2008	2007	2006	2005	2004
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	217.0	211.0	212.0	193.0	153.0	135.7	87.3	9.5	9.8	2.8	249	242	243	221	175
ATO	† ATMOS ENERGY CORP	SEP	180.3	168.5	147.7	135.8	86.2	79.5	55.3	12.6	17.8	7.0	326	305	267	246	156
EGN	† ENERGEN CORP	DEC	321.9	309.2	273.5	172.9	127.4	110.3	36.2	24.4	23.9	4.1	888	853	755	477	352
EQT	[] EQT CORP	DEC	255.6	257.5	216.0	258.6	279.9	173.6	(27.1)	NM	8.1	(0.7)	NM	NM	NM	NM	NM
LG	§ LACLEDE GROUP INC	SEP	57.6	49.8	49.0	40.1	36.1	34.6	27.9	7.5	10.7	15.6	206	179	176	144	129
NFG	† NATIONAL FUEL GAS CO	SEP	268.7	201.7	138.1	153.5	166.6	187.8	32.3	23.6	7.4	33.2	832	624	427	475	516
NJR	§ NEW JERSEY RESOURCES CORP	SEP	113.9	65.3	78.5	76.3	71.6	65.4	43.3	10.1	11.7	74.5	263	151	181	176	165
GAS	[] NICOR INC	DEC	119.5	135.2	128.3	136.3	75.1	109.7	116.4	0.3	1.7	(11.6)	103	116	110	117	65
NWN	§ NORTHWEST NATURAL GAS CO	DEC	69.5	74.5	63.4	58.1	50.6	46.0	27.3	9.8	8.6	(6.7)	255	273	232	213	185
OKE	† ONEOK INC	DEC	311.9	304.9	306.7	403.1	242.2	214.3	101.8	11.8	7.8	2.3	306	300	301	396	238
PNY	§ PIEDMONT NATURAL GAS CO	OCT	110.0	104.4	97.2	101.3	95.2	74.4	60.3	6.2	8.1	5.4	182	173	161	168	158
STR	[] QUESTAR CORP	DEC	683.8	507.4	444.1	325.7	229.3	179.2	76.9	24.4	30.7	34.8	889	660	578	424	298
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	77.2	62.7	72.3	48.6	43.0	34.6	13.8	18.8	17.4	23.2	559	454	523	352	311
SWX	§ SOUTHWEST GAS CORP	DEC	61.0	83.2	83.9	43.8	56.8	38.5	47.5	2.5	9.6	(26.8)	128	175	176	92	119
UGI	† UGI CORP	SEP	215.5	204.3	176.2	187.5	111.6	98.9	42.5	17.6	16.9	5.5	507	481	415	441	263
WGL	† WGL HOLDINGS INC	SEP	117.8	109.2	96.0	104.8	98.0	113.7	68.6	5.6	0.7	7.9	172	159	140	153	143
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	298.7	443.4	357.0	75.1	229.5	176.6	103.4	11.2	11.1	(32.6)	289	429	345	73	222
AEE	[] AMEREN CORP	DEC	615.0	629.0	558.0	641.0	541.0	517.0	399.1	4.4	3.5	(2.2)	154	158	140	161	136
AVA	§ AVISTA CORP	DEC	73.6	38.5	73.1	45.2	35.6	50.6	78.1	(0.6)	7.8	91.3	94	49	94	58	46
BKH	† BLACK HILLS CORP	DEC	(52.2)	100.1	74.0	35.8	57.2	57.0	25.8	NM	NM	NM	(202)	388	287	139	222
CNP	[] CENTERPOINT ENERGY INC	DEC	447.0	399.0	432.0	225.0	205.7	419.7	(141.1)	NM	1.3	12.0	NM	NM	NM	NM	NM
CHG	§ CH ENERGY GROUP INC	DEC	36.1	43.6	44.1	45.3	43.4	45.4	52.5	(3.7)	(4.5)	(17.3)	69	83	84	86	83
CMS	[] CMS ENERGY CORP	DEC	300.0	(124.0)	(80.0)	(93.0)	132.0	(40.0)	261.0	1.4	NM	NM	115	(48)	(31)	(36)	51
ED	[] CONSOLIDATED EDISON INC	DEC	933.0	936.0	749.0	743.0	560.0	536.0	729.7	2.5	11.7	(0.3)	128	128	103	102	77
D	[] DOMINION RESOURCES INC	DEC	1,853.0	2,721.0	1,579.0	1,050.0	1,280.0	964.0	571.4	12.5	14.0	(31.9)	324	476	276	184	224
DTE	[] DTE ENERGY CO	DEC	526.0	787.0	437.0	576.0	443.0	480.0	449.0	1.6	1.8	(33.2)	117	175	97	128	99
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	124.8	181.1	151.6	162.1	156.2	110.6	49.8	9.6	2.4	(31.1)	251	364	305	326	314
MDU	† MDU RESOURCES GROUP INC	DEC	293.7	322.8	317.9	275.1	207.1	182.9	34.1	24.0	9.9	(9.0)	861	946	932	807	607
NI	[] NISOURCE INC	DEC	369.8	312.0	314.6	287.8	434.6	430.2	202.4	6.2	(3.0)	18.5	183	154	155	142	215
NST	† NSTAR	DEC	239.5	223.5	208.7	198.1	190.4	183.5	141.0	5.4	5.5	7.2	170	158	148	140	135
OGE	† OGE ENERGY CORP	DEC	231.4	244.2	226.1	166.1	153.0	135.6	165.9	3.4	11.3	(5.2)	140	147	136	100	92
PCG	[] PG&E CORP	DEC	1,184.0	1,006.0	991.0	904.0	3,820.0	791.0	746.0	4.7	8.4	17.7	159	135	133	121	512
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	987.0	1,323.0	756.0	862.0	725.0	856.0	653.0	4.2	2.9	(25.4)	151	203	116	132	111
SCG	[] SCANA CORP	DEC	353.0	327.0	311.0	327.0	264.0	289.0	231.0	4.3	4.1	8.0	153	142	135	142	114
SRE	[] SEMPRA ENERGY	DEC	1,123.0	1,135.0	1,101.0	939.0	930.0	705.0	306.0	13.9	9.8	(1.1)	367	371	360	307	304
TE	[] TECO ENERGY INC	DEC	162.4	398.9	244.4	211.0	(404.4)	(14.7)	200.4	(2.1)	NM	(59.3)	81	199	122	105	(202)
VVC	† VECTREN CORP	DEC	129.0	143.1	108.8	136.8	107.9	111.2	40.2	12.4	3.0	(9.9)	321	356	271	340	268
WEC	[] WISCONSIN ENERGY CORP	DEC	358.6	336.5	312.5	303.6	122.2	245.5	189.3	6.6	7.9	6.6	189	178	165	160	65
XEL	[] XCEL ENERGY INC	DEC	645.7	575.9	568.7	499.0	526.9	510.0	282.4	8.6	4.8	12.1	229	204	201	177	187
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AWR	§ AMERICAN STATES WATER CO	DEC	22.0	28.0	23.1	26.8	18.5	11.9	14.6	4.2	13.1	(21.5)	150	192	158	183	127
WTR	† AQUA AMERICA INC	DEC	97.9	95.0	92.0	91.2	80.0	70.8	28.8	13.0	6.7	3.1	340	330	319	316	278
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	1,194.4	1,260.0	920.9	1,056.1	832.6	636.8	277.1	15.7	13.4	(5.2)	431	455	332	381	301

Note: Data as originally reported. CAGR-Compound annual growth rate. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.
#Of the following calendar year. **Not calculated; data for base year or end year not available.

Ticker		Company	Yr. End	Return on Revenues (%) 2008	2007	2006	2005	2004	Return on Assets (%) 2008	2007	2006	2005	2004	Return on Equity (%) 2008	2007	2006	2005	2004
GAS UTILITIES‡																		
AGL	†	AGL RESOURCES INC	DEC	7.8	8.5	8.1	7.1	8.4	3.3	3.4	3.4	3.2	3.2	13.1	12.9	13.6	13.4	13.1
ATO	†	ATMOS ENERGY CORP	SEP	2.5	2.9	2.4	2.7	3.0	2.9	2.9	2.6	3.2	3.2	9.0	9.3	9.1	9.9	8.7
EGN	†	ENERGEN CORP	DEC	20.5	21.5	20.4	15.3	13.6	9.4	10.5	10.0	7.2	6.4	19.6	24.0	26.1	20.4	17.0
EQT	[]	EQT CORP	DEC	16.2	18.9	17.0	20.6	23.5	5.5	7.2	6.5	7.9	9.1	16.2	25.2	33.2	42.1	30.4
LG	§	LACLEDE GROUP INC	SEP	2.6	2.5	2.5	2.5	2.9	3.4	3.1	3.3	3.0	2.9	12.6	12.0	12.7	11.1	11.0
NFG	†	NATIONAL FUEL GAS CO	SEP	11.2	9.9	6.0	8.0	8.2	6.7	5.3	3.7	4.1	4.5	16.6	13.1	10.3	12.4	13.9
NJR	§	NEW JERSEY RESOURCES CORP	SEP	3.0	2.2	2.4	2.4	2.8	4.7	2.8	3.4	3.8	4.2	16.6	10.3	14.8	16.9	16.1
GAS	[]	NICOR INC	DEC	3.2	4.3	4.3	4.1	2.7	2.6	3.2	3.0	3.3	1.9	12.5	14.9	15.2	17.5	10.0
NWN	§	NORTHWEST NATURAL GAS CO	DEC	6.7	7.2	6.3	6.4	7.1	3.2	3.8	3.2	3.1	3.0	11.4	12.5	10.7	10.1	9.4
OKE	†	ONEOK INC	DEC	1.9	2.3	2.6	3.2	4.0	2.6	2.8	3.0	4.7	3.6	15.4	14.6	15.3	23.7	17.0
PNY	§	PIEDMONT NATURAL GAS CO	OCT	5.3	6.1	5.0	5.8	6.2	3.7	3.8	3.6	4.1	4.1	12.5	11.9	11.0	11.6	12.8
STR	[]	QUESTAR CORP	DEC	19.7	18.6	15.7	12.0	12.1	9.4	9.2	9.4	8.1	6.6	22.8	21.2	23.7	21.8	17.0
SJI	§	SOUTH JERSEY INDUSTRIES INC	DEC	8.0	6.6	7.8	5.3	5.2	4.6	4.0	4.8	3.6	3.6	15.5	13.6	17.3	13.2	13.4
SWX	§	SOUTHWEST GAS CORP	DEC	2.8	3.9	4.1	2.6	3.8	1.6	2.3	2.5	1.4	2.0	6.0	8.8	10.1	6.0	8.5
UGI	†	UGI CORP	SEP	3.2	3.7	3.4	3.8	2.9	3.9	3.9	3.7	4.3	3.2	15.7	16.9	16.8	20.5	15.9
WGL	†	WGL HOLDINGS INC	SEP	4.5	4.1	3.6	7.6	7.7	3.7	3.7	3.5	4.1	3.9	11.5	11.3	10.4	11.8	11.6
MULTI-UTILITIES‡																		
LNT	†	ALLIANT ENERGY CORP	DEC	8.1	12.9	10.6	2.3	7.8	3.6	6.0	4.6	0.7	2.6	10.2	15.9	13.3	2.3	8.5
AEE	[]	AMEREN CORP	DEC	7.8	8.3	8.1	9.5	10.5	2.8	3.1	2.9	3.5	3.3	8.8	9.3	8.4	10.3	10.4
AVA	§	AVISTA CORP	DEC	4.4	2.7	4.9	3.3	3.1	2.2	1.1	1.6	1.0	1.0	7.7	4.2	8.7	5.9	4.7
BKH	†	BLACK HILLS CORP	DEC	NM	14.4	11.3	2.6	5.1	NM	4.2	3.4	1.7	2.8	NM	11.4	9.7	4.9	8.0
CNP	[]	CENTERPOINT ENERGY INC	DEC	3.9	4.1	4.6	2.3	2.4	2.4	2.2	2.5	1.3	1.0	23.2	23.7	30.3	18.7	14.4
CHG	§	CH ENERGY GROUP INC	DEC	2.7	3.6	4.4	4.7	5.5	2.2	2.9	3.0	3.3	3.3	6.7	8.2	8.5	8.9	8.7
CMS	[]	CMS ENERGY CORP	DEC	4.4	NM	NM	NM	2.4	2.0	NM	NM	NM	0.8	12.6	NM	NM	NM	6.3
ED	[]	CONSOLIDATED EDISON INC	DEC	6.9	7.1	6.2	6.4	5.7	3.0	3.4	2.9	3.1	2.5	9.8	10.8	9.6	10.2	8.1
D	[]	DOMINION RESOURCES INC	DEC	11.4	17.4	9.6	5.8	9.2	4.5	6.1	3.1	2.1	2.8	18.8	24.2	13.4	9.5	11.5
DTE	[]	DTE ENERGY CO	DEC	5.6	9.3	4.8	6.4	6.2	2.2	3.3	1.9	2.6	2.1	8.9	13.5	7.5	10.2	8.2
TEG	[]	INTEGRYS ENERGY GROUP INC	DEC	0.9	1.8	2.2	2.3	3.2	1.0	2.0	2.4	3.2	3.5	3.8	7.5	10.5	13.3	14.6
MDU	†	MDU RESOURCES GROUP INC	DEC	5.9	7.6	7.8	8.0	7.6	4.8	6.1	6.8	6.7	5.8	11.1	13.8	15.8	15.5	13.3
NI	[]	NISOURCE INC	DEC	4.2	3.9	4.2	3.6	6.5	1.9	1.7	1.7	1.6	2.6	7.5	6.2	6.3	5.8	9.3
NST	†	NSTAR	DEC	7.2	6.9	5.8	6.1	6.4	3.0	2.9	2.7	2.7	2.8	13.6	13.5	13.3	13.2	13.5
OGE	†	OGE ENERGY CORP	DEC	5.7	6.4	5.6	2.8	3.1	3.9	4.8	4.6	3.4	3.2	12.9	14.9	15.2	12.5	12.3
PCG	[]	PG&E CORP	DEC	8.1	7.6	7.9	7.7	34.5	3.1	2.8	2.9	2.6	11.8	13.2	12.3	13.2	11.4	59.5
PEG	[]	PUBLIC SERVICE ENTRP GRP INC	DEC	7.1	10.3	6.2	6.9	6.6	3.4	4.6	2.6	2.9	2.5	13.0	18.8	11.8	14.6	12.8
SCG	[]	SCANA CORP	DEC	6.6	7.1	6.8	6.8	6.8	3.2	3.2	3.1	3.5	2.9	11.5	11.0	11.0	12.5	10.8
SRE	[]	SEMPRA ENERGY	DEC	10.4	9.9	9.4	8.0	9.9	3.9	3.8	3.8	3.5	4.0	13.6	14.2	16.0	16.9	21.0
TE	[]	TECO ENERGY INC	DEC	4.8	11.3	7.1	7.0	NM	2.3	5.6	3.4	2.5	NM	8.1	21.3	14.7	14.7	NM
VVC	†	VECTREN CORP	DEC	5.2	6.3	5.3	6.7	6.4	2.9	3.4	2.7	3.7	3.1	10.0	11.9	9.4	12.2	10.0
WEC	[]	WISCONSIN ENERGY CORP	DEC	8.1	7.9	7.8	8.0	3.6	2.9	2.9	2.9	3.0	1.2	11.1	11.2	11.2	11.7	5.0
XEL	[]	XCEL ENERGY INC	DEC	5.8	5.7	5.8	5.2	6.3	2.7	2.5	2.6	2.4	2.6	9.7	9.4	10.1	9.3	10.1
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																		
AWR	§	AMERICAN STATES WATER CO	DEC	6.9	9.3	8.6	11.3	8.1	2.2	2.9	2.5	3.2	2.4	7.2	9.6	8.4	10.4	8.0
WTR	†	AQUA AMERICA INC	DEC	15.6	15.8	17.2	18.3	18.1	2.9	3.1	3.3	3.7	3.6	9.6	10.0	10.6	11.7	11.4
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																		
TRP		TRANSCANADA CORP	DEC	17.0	14.1	14.3	20.1	19.6	3.7	4.7	4.2	5.3	4.8	11.5	15.0	14.1	17.8	16.0

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Ticker	Company	Yr. End	Current Ratio 2008	2007	2006	2005	2004	Debt / Capital Ratio (%) 2008	2007	2006	2005	2004	Debt as a % of Net Working Capital 2008	2007	2006	2005	2004
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	1.0	1.1	1.1	1.0	1.0	42.5	42.2	42.3	44.9	46.4	NM	NM	831.8	NM	NM
ATO	† ATMOS ENERGY CORP	SEP	1.1	1.2	1.0	1.1	1.6	50.8	52.0	57.0	57.7	43.2	NM	NM	NM	NM	327.9
EGN	† ENERGEN CORP	DEC	1.3	0.7	0.9	0.7	0.7	22.7	29.0	32.6	43.4	43.3	422.5	NM	NM	NM	NM
EQT	[] EQT CORP	DEC	0.9	0.5	0.6	0.5	0.6	37.9	40.7	44.3	68.3	31.0	NM	NM	NM	NM	NM
LG	§ LACLEDE GROUP INC	SEP	1.2	1.0	1.1	1.2	1.3	35.3	35.1	38.2	37.9	40.8	470.6	NM	NM	581.3	507.1
NFG	† NATIONAL FUEL GAS CO	SEP	1.3	1.3	1.8	1.2	0.8	30.8	26.5	35.5	39.3	39.2	799.8	696.0	478.2	991.9	NM
NJR	§ NEW JERSEY RESOURCES CORP	SEP	1.2	1.1	1.1	1.0	1.0	31.8	30.6	28.0	36.5	34.1	211.0	396.7	486.1	NM	NM
GAS	[] NICOR INC	DEC	0.8	0.8	0.8	0.8	0.9	24.3	23.6	27.7	27.8	26.5	NM	NM	NM	NM	NM
NWN	§ NORTHWEST NATURAL GAS CO	DEC	0.9	0.7	0.9	1.0	0.9	44.9	46.3	46.3	39.0	38.1	NM	NM	NM	NM	NM
OKE	† ONEOK INC	DEC	0.8	1.0	1.6	0.9	0.9	56.5	60.3	57.2	53.0	50.4	NM	NM	343.2	NM	NM
PNY	§ PIEDMONT NATURAL GAS CO	OCT	0.9	1.0	1.2	1.0	1.1	39.9	41.8	42.4	36.2	38.3	NM	NM	NM	NM	NM
STR	[] QUESTAR CORP	DEC	1.0	0.7	1.1	0.9	0.9	30.3	22.5	25.6	31.1	32.1	NM	NM	NM	NM	NM
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	0.9	1.0	0.9	0.9	1.0	32.1	35.2	36.5	36.1	40.0	NM	NM	NM	NM	NM
SWX	§ SOUTHWEST GAS CORP	DEC	0.9	1.0	1.0	0.9	0.9	55.3	58.1	60.6	63.8	64.2	NM	NM	NM	NM	NM
UGI	† UGI CORP	SEP	1.1	1.1	1.0	1.0	0.9	48.9	50.1	53.1	45.2	51.4	NM	NM	NM	NM	NM
WGL	† WGL HOLDINGS INC	SEP	1.0	1.0	1.0	1.2	1.0	30.8	32.4	31.4	32.2	33.6	NM	NM	NM	840.3	NM
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	1.4	1.6	1.1	1.1	1.2	36.3	32.4	31.3	37.0	38.5	429.1	262.4	NM	942.8	NM
AEE	[] AMEREN CORP	DEC	0.8	0.9	0.9	1.2	0.9	41.1	38.5	36.9	38.3	38.6	NM	NM	NM	NM	NM
AVA	§ AVISTA CORP	DEC	0.7	0.4	1.1	1.0	1.0	48.1	41.0	53.7	59.4	58.1	NM	NM	NM	NM	NM
BKH	† BLACK HILLS CORP	DEC	0.6	0.9	0.9	1.2	1.3	32.3	36.7	44.1	47.4	49.8	NM	NM	NM	939.4	598.5
CNP	[] CENTERPOINT ENERGY INC	DEC	1.1	0.7	0.7	1.0	0.5	68.6	67.2	66.6	69.2	66.8	NM	NM	NM	NM	NM
CHG	§ CH ENERGY GROUP INC	DEC	1.3	1.5	1.4	2.2	2.6	43.1	42.5	38.7	39.6	38.3	622.2	411.7	450.4	211.3	194.0
CMS	[] CMS ENERGY CORP	DEC	1.5	1.2	1.5	1.8	1.7	68.3	69.5	69.5	68.7	65.3	647.6	NM	650.7	408.0	583.8
ED	[] CONSOLIDATED EDISON INC	DEC	1.0	0.7	1.0	0.9	0.8	38.3	35.6	40.3	39.7	37.4	NM	NM	NM	NM	NM
D	[] DOMINION RESOURCES INC	DEC	1.0	0.9	0.7	0.7	0.9	59.1	57.7	43.7	48.4	47.4	NM	NM	NM	NM	NM
DTE	[] DTE ENERGY CO	DEC	1.1	0.9	1.0	1.0	1.0	48.9	47.1	50.0	48.9	52.3	NM	NM	NM	NM	NM
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	1.0	1.1	1.0	1.1	1.1	38.7	37.2	43.1	37.8	41.4	NM	473.8	NM	492.7	625.5
MDU	† MDU RESOURCES GROUP INC	DEC	1.3	1.4	1.5	1.5	1.6	36.2	31.2	35.1	36.9	34.2	514.6	314.7	344.5	363.1	313.0
NI	[] NISOURCE INC	DEC	0.7	0.7	0.7	0.8	0.6	48.4	45.5	43.7	44.1	42.2	NM	NM	NM	NM	NM
NST	† NSTAR	DEC	0.8	0.9	0.8	0.9	0.8	44.0	46.5	45.2	60.4	58.6	NM	NM	NM	NM	NM
OGE	† OGE ENERGY CORP	DEC	0.8	0.6	1.0	1.1	1.0	42.6	34.5	35.1	37.9	40.1	NM	NM	NM	NM	NM
PCG	[] PG&E CORP	DEC	0.8	0.8	0.7	0.9	0.9	44.5	44.9	44.0	47.2	39.0	NM	NM	NM	NM	NM
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1.2	1.1	1.1	1.0	1.0	50.5	54.0	60.3	64.9	69.0	NM	NM	NM	NM	NM
SCG	[] SCANA CORP	DEC	1.6	0.8	1.0	1.0	1.0	50.5	41.1	43.2	43.4	47.2	640.4	NM	NM	NM	NM
SRE	[] SEMPRA ENERGY	DEC	0.7	1.1	1.2	1.1	1.0	41.4	33.5	36.5	42.8	44.0	NM	493.1	281.2	429.4	NM
TE	[] TECO ENERGY INC	DEC	1.0	1.3	1.0	1.4	0.3	61.5	61.0	65.0	70.0	68.2	NM	NM	NM	NM	NM
VVC	† VECTREN CORP	DEC	0.7	0.7	0.7	0.9	0.7	42.2	44.4	45.5	51.2	48.1	NM	NM	NM	NM	NM
WEC	[] WISCONSIN ENERGY CORP	DEC	1.0	0.7	0.7	0.8	1.2	49.1	46.0	46.4	47.4	51.0	NM	NM	NM	NM	NM
XEL	[] XCEL ENERGY INC	DEC	1.0	0.8	0.9	0.9	1.1	43.7	41.1	43.7	43.0	46.3	NM	NM	NM	NM	NM
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AWR	§ AMERICAN STATES WATER CO	DEC	0.7	0.7	0.8	0.9	0.6	40.1	40.8	42.2	44.4	43.3	NM	NM	NM	NM	NM
WTR	† AQUA AMERICA INC	DEC	0.6	0.6	0.5	0.3	0.4	46.9	48.6	44.3	45.2	44.7	NM	NM	NM	NM	NM
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	0.7	0.8	0.7	0.5	0.4	53.3	54.3	57.4	56.1	56.1	NM	NM	NM	NM	NM

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Ticker		Company	Yr. End	Price / Earnings Ratio (High-Low) 2008	2007	2006	2005	2004	Dividend Payout Ratio (%) 2008	2007	2006	2005	2004	Dividend Yield (High-Low, %) 2008	2007	2006	2005	2004
GAS UTILITIES‡																		
AGL	†	AGL RESOURCES INC	DEC	14 - 8	16 - 13	15 - 13	16 - 13	15 - 12	59	60	54	52	50	7.0 - 4.3	4.7 - 3.7	4.3 - 3.7	4.1 - 3.3	4.3 - 3.4
ATO	†	ATMOS ENERGY CORP	SEP	15 - 10	17 - 12	18 - 14	17 - 14	17 - 15	64	66	69	72	76	6.6 - 4.4	5.4 - 3.8	4.9 - 3.8	5.0 - 4.1	5.2 - 4.4
EGN	†	ENERGEN CORP	DEC	18 - 5	16 - 10	13 - 9	19 - 11	17 - 11	11	11	12	17	22	2.1 - 0.6	1.1 - 0.7	1.4 - 0.9	1.5 - 0.9	1.9 - 1.3
EQT	[]	EQT CORP	DEC	38 - 10	27 - 19	25 - 18	19 - 13	13 - 9	44	42	49	38	32	4.2 - 1.2	2.2 - 1.6	2.8 - 2.0	2.9 - 2.0	3.4 - 2.4
LG	§	LACLEDE GROUP INC	SEP	21 - 12	16 - 12	16 - 13	18 - 14	18 - 14	56	63	61	72	74	4.7 - 2.7	5.1 - 4.1	4.8 - 3.8	5.1 - 4.0	5.2 - 4.2
NFG	†	NATIONAL FUEL GAS CO	SEP	19 - 8	21 - 15	25 - 19	20 - 14	14 - 12	39	50	72	62	54	4.7 - 2.0	3.3 - 2.4	3.9 - 2.9	4.4 - 3.2	4.6 - 3.8
NJR	§	NEW JERSEY RESOURCES CORP	SEP	15 - 8	24 - 19	19 - 15	18 - 15	17 - 14	41	65	51	49	50	5.1 - 2.7	3.3 - 2.7	3.5 - 2.7	3.3 - 2.8	3.6 - 2.9
GAS	[]	NICOR INC	DEC	20 - 12	18 - 13	17 - 13	14 - 12	23 - 19	70	62	65	60	109	5.7 - 3.6	4.9 - 3.5	4.8 - 3.7	5.2 - 4.3	5.8 - 4.7
NWN	§	NORTHWEST NATURAL GAS CO	DEC	21 - 14	19 - 14	19 - 14	19 - 15	18 - 15	58	52	60	63	70	4.2 - 2.8	3.6 - 2.7	4.2 - 3.2	4.1 - 3.3	4.7 - 3.8
OKE	†	ONEOK INC	DEC	17 - 7	19 - 14	16 - 10	9 - 7	12 - 8	52	49	45	27	37	7.2 - 3.0	3.6 - 2.5	4.6 - 2.7	4.1 - 3.0	4.5 - 3.0
PNY	§	PIEDMONT NATURAL GAS CO	OCT	24 - 14	20 - 16	22 - 18	20 - 16	19 - 15	69	70	74	69	67	5.0 - 2.9	4.5 - 3.5	4.1 - 3.3	4.3 - 3.5	4.4 - 3.5
STR	[]	QUESTAR CORP	DEC	19 - 5	20 - 13	18 - 13	23 - 12	19 - 12	12	16	18	23	31	2.4 - 0.7	1.3 - 0.8	1.4 - 1.0	1.9 - 1.0	2.5 - 1.6
SJI	§	SOUTH JERSEY INDUSTRIES INC	DEC	16 - 10	19 - 15	14 - 10	19 - 15	17 - 13	43	47	37	50	52	4.4 - 2.7	3.2 - 2.4	3.6 - 2.7	3.5 - 2.7	4.2 - 3.1
SWX	§	SOUTHWEST GAS CORP	DEC	24 - 15	20 - 13	19 - 13	24 - 20	16 - 13	64	43	40	71	51	4.2 - 2.7	3.2 - 2.1	3.1 - 2.1	3.5 - 2.9	3.8 - 3.1
UGI	†	UGI CORP	SEP	14 - 9	15 - 12	17 - 12	17 - 11	18 - 13	38	38	41	36	51	4.0 - 2.6	3.2 - 2.4	3.3 - 2.4	3.4 - 2.2	4.0 - 2.9
WGL	†	WGL HOLDINGS INC	SEP	16 - 10	16 - 14	17 - 14	16 - 14	16 - 13	59	62	69	62	65	6.2 - 3.8	4.6 - 3.8	5.0 - 4.0	4.6 - 3.8	4.8 - 4.1
MULTI-UTILITIES‡																		
LNT	†	ALLIANT ENERGY CORP	DEC	17 - 9	12 - 9	14 - 10	64 - 53	15 - 13	55	34	40	219	54	6.1 - 3.3	3.6 - 2.7	4.1 - 2.9	4.1 - 3.4	4.3 - 3.5
AEE	[]	AMEREN CORP	DEC	19 - 9	18 - 16	21 - 18	18 - 15	18 - 14	88	85	95	81	89	10.0 - 4.7	5.4 - 4.6	5.3 - 4.6	5.3 - 4.5	6.3 - 5.0
AVA	§	AVISTA CORP	DEC	17 - 11	35 - 25	18 - 12	22 - 18	26 - 21	50	82	38	59	70	4.4 - 2.9	3.3 - 2.3	3.2 - 2.1	3.3 - 2.7	3.4 - 2.7
BKH	†	BLACK HILLS CORP	DEC	NM - NM	17 - 13	17 - 15	41 - 27	18 - 15	NM	51	59	117	70	6.4 - 3.2	3.9 - 3.0	4.1 - 3.5	4.4 - 2.9	4.7 - 3.8
CNP	[]	CENTERPOINT ENERGY INC	DEC	13 - 6	16 - 12	12 - 8	21 - 15	18 - 14	55	54	43	56	60	8.6 - 4.2	4.6 - 3.4	5.2 - 3.6	3.8 - 2.6	4.1 - 3.2
CHG	§	CH ENERGY GROUP INC	DEC	24 - 15	20 - 15	20 - 16	18 - 15	18 - 16	97	80	79	77	80	6.5 - 4.1	5.2 - 4.0	4.8 - 3.9	5.1 - 4.3	5.0 - 4.4
CMS	[]	CMS ENERGY CORP	DEC	14 - 6	NM - NM	NM - NM	NM - NM	16 - 11	28	NM	NM	NM	0	4.3 - 2.1	1.3 - 1.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
ED	[]	CONSOLIDATED EDISON INC	DEC	15 - 10	15 - 12	17 - 14	16 - 14	20 - 16	69	67	78	76	97	6.9 - 4.7	5.4 - 4.4	5.6 - 4.7	5.5 - 4.6	6.1 - 5.0
D	[]	DOMINION RESOURCES INC	DEC	15 - 10	12 - 10	19 - 15	29 - 22	18 - 16	50	35	62	89	68	5.1 - 3.3	3.7 - 3.0	4.0 - 3.3	4.0 - 3.1	4.3 - 3.8
DTE	[]	DTE ENERGY CO	DEC	14 - 9	12 - 9	20 - 16	15 - 13	18 - 15	65	46	84	63	80	7.6 - 4.7	4.8 - 3.9	5.4 - 4.2	5.0 - 4.3	5.4 - 4.5
TEG	[]	INTEGRYS ENERGY GROUP INC	DEC	34 - 23	24 - 19	16 - 14	14 - 11	12 - 11	169	101	65	54	54	7.3 - 5.0	5.2 - 4.1	4.8 - 3.9	4.7 - 3.7	5.1 - 4.4
MDU	†	MDU RESOURCES GROUP INC	DEC	22 - 10	18 - 14	15 - 12	16 - 11	16 - 12	38	32	30	32	40	3.9 - 1.7	2.3 - 1.8	2.4 - 1.9	2.9 - 2.0	3.2 - 2.5
NI	[]	NISOURCE INC	DEC	15 - 8	22 - 15	22 - 17	24 - 19	14 - 12	68	81	80	88	56	8.9 - 4.6	5.3 - 3.6	4.7 - 3.7	4.5 - 3.6	4.7 - 4.0
NST	†	NSTAR	DEC	18 - 12	18 - 15	19 - 14	17 - 14	15 - 13	63	63	62	63	63	5.5 - 3.5	4.2 - 3.5	4.6 - 3.4	4.7 - 3.7	4.9 - 4.1
OGE	†	OGE ENERGY CORP	DEC	14 - 8	16 - 11	16 - 11	17 - 13	16 - 13	56	51	54	72	77	7.1 - 3.8	4.7 - 3.3	5.0 - 3.3	5.4 - 4.3	5.8 - 4.9
PCG	[]	PG&E CORP	DEC	14 - 8	18 - 15	17 - 13	17 - 13	4 - 3	47	50	46	51	0	5.8 - 3.4	3.4 - 2.8	3.6 - 2.7	3.9 - 3.1	0.0 - 0.0
PEG	[]	PUBLIC SERVICE ENTRP GRP INC	DEC	27 - 11	19 - 12	24 - 20	19 - 14	17 - 13	66	45	76	63	72	5.8 - 2.5	3.6 - 2.3	3.9 - 3.1	4.5 - 3.3	5.8 - 4.2
SCG	[]	SCANA CORP	DEC	15 - 9	17 - 12	16 - 14	16 - 13	17 - 14	62	64	64	56	63	6.6 - 4.2	5.3 - 3.9	4.6 - 4.0	4.3 - 3.6	4.4 - 3.7
SRE	[]	SEMPRA ENERGY	DEC	14 - 8	15 - 12	13 - 10	13 - 9	9 - 7	30	29	28	31	25	4.0 - 2.2	2.4 - 1.9	2.8 - 2.1	3.3 - 2.4	3.4 - 2.6
TE	[]	TECO ENERGY INC	DEC	29 - 14	10 - 8	15 - 12	19 - 15	NM - NM	103	41	64	75	NM	7.6 - 3.6	5.2 - 4.2	5.3 - 4.3	5.1 - 3.9	6.7 - 4.9
VVC	†	VECTREN CORP	DEC	20 - 12	16 - 13	20 - 18	16 - 14	19 - 16	79	67	85	66	80	6.7 - 4.1	5.1 - 4.2	4.9 - 4.2	4.8 - 4.0	5.0 - 4.2
WEC	[]	WISCONSIN ENERGY CORP	DEC	16 - 11	18 - 14	18 - 14	16 - 13	33 - 28	35	35	34	34	80	3.1 - 2.2	2.4 - 2.0	2.4 - 1.9	2.6 - 2.2	2.8 - 2.4
XEL	[]	XCEL ENERGY INC	DEC	16 - 10	18 - 14	17 - 13	16 - 13	14 - 12	64	66	63	69	62	6.2 - 4.1	4.7 - 3.6	5.0 - 3.7	5.2 - 4.2	5.2 - 4.3
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																		
AWR	§	AMERICAN STATES WATER CO	DEC	33 - 21	28 - 21	33 - 23	22 - 15	23 - 17	79	59	68	57	75	3.7 - 2.4	2.8 - 2.1	3.0 - 2.1	3.7 - 2.6	4.3 - 3.3
WTR	†	AQUA AMERICA INC	DEC	30 - 17	37 - 26	43 - 29	41 - 24	29 - 22	70	67	63	55	57	4.2 - 2.3	2.5 - 1.8	2.2 - 1.5	2.3 - 1.4	2.6 - 2.0
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																		
TRP		TRANSCANADA CORP	DEC	20 - 11	19 - 13	19 - 15	15 - 11	15 - 11	65	55	61	47	54	5.7 - 3.3	4.1 - 2.9	4.1 - 3.2	4.4 - 3.1	4.8 - 3.6

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Ticker	Company	Yr. End	Earnings per Share ($) 2008	2007	2006	2005	2004	Tangible Book Value per Share ($) 2008	2007	2006	2005	2004	Share Price (High-Low, $) 2008	2007	2006	2005	2004
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	2.85	2.74	2.73	2.50	2.30	16.05	16.24	15.30	13.84	13.44	39.13 - 24.02	44.67 - 35.24	40.09 - 34.40	39.32 - 32.00	33.65 - 26.50
ATO	† ATMOS ENERGY CORP	SEP	2.02	1.94	1.83	1.73	1.60	14.46	13.75	11.13	10.74	14.25	29.29 - 19.68	33.47 - 23.87	33.09 - 25.55	29.97 - 25.00	27.59 - 23.40
EGN	† ENERGEN CORP	DEC	4.50	4.32	3.77	2.37	1.75	26.74	19.47	17.06	12.33	11.14	79.57 - 23.00	70.41 - 43.78	47.60 - 32.16	44.31 - 27.06	30.03 - 19.93
EQT	[] EQT CORP	DEC	2.01	2.12	1.79	2.14	2.27	15.67 J	8.98 J	7.78 J	2.96 J	6.74	76.14 - 20.71	56.75 - 39.26	44.48 - 31.59	41.18 - 27.89	30.59 - 21.05
LG	§ LACLEDE GROUP INC	SEP	2.66	2.32	2.31	1.90	1.82	22.12	18.24	17.28	15.98	15.62	55.81 - 31.86	36.03 - 28.84	37.51 - 29.09	34.31 - 26.90	32.50 - 26.05
NFG	† NATIONAL FUEL GAS CO	SEP	3.27	2.43	1.64	1.84	2.03	19.87	19.12	16.86	14.01	14.49	63.71 - 26.83	50.29 - 36.94	40.21 - 30.60	36.00 - 26.20	29.18 - 23.75
NJR	§ NEW JERSEY RESOURCES CORP	SEP	2.72	1.56	1.88	1.85	1.73	17.29	15.50	15.00	10.60	11.24	41.13 - 21.90	37.63 - 30.33	35.44 - 27.66	32.89 - 27.12	29.70 - 24.33
GAS	[] NICOR INC	DEC	2.64	2.99	2.88	3.08	1.71	21.02	20.51	19.01	18.36 J	16.99	51.99 - 32.35	53.66 - 37.80	49.92 - 38.72	42.97 - 35.50	39.65 - 32.04
NWN	§ NORTHWEST NATURAL GAS CO	DEC	2.63	2.78	2.30	2.11	1.87	23.71	22.52	21.97	21.28	20.64	55.23 - 36.61	52.85 - 39.79	43.69 - 32.83	39.63 - 32.42	34.13 - 27.46
OKE	† ONEOK INC	DEC	2.99	2.84	2.74	4.01	2.38	10.01	8.90	10.52	11.38	13.26	51.33 - 21.56	55.27 - 39.26	44.48 - 26.35	35.85 - 26.30	28.99 - 19.69
PNY	§ PIEDMONT NATURAL GAS CO	OCT	1.50	1.41	1.28	1.32	1.28	11.45	11.18	11.07	10.91	10.52	35.29 - 20.52	27.98 - 22.00	28.44 - 23.21	25.80 - 21.26	24.35 - 19.16
STR	[] QUESTAR CORP	DEC	3.96	2.95	2.60	1.92	1.37	19.29	14.51	12.43	8.60	8.03	74.86 - 20.66	58.75 - 37.98	45.51 - 33.69	44.80 - 23.36	26.06 - 16.91
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	2.60	2.13	2.48	1.72	1.57	17.33 J	16.25 J	15.11 J	13.50 J	12.41 J	40.58 - 25.19	41.27 - 31.20	34.26 - 25.63	32.38 - 24.94	26.55 - 19.68
SWX	§ SOUTHWEST GAS CORP	DEC	1.40	1.97	2.07	1.15	1.61	23.48	22.98	21.58	19.10	19.18	33.29 - 21.11	39.95 - 26.45	39.37 - 26.09	28.07 - 23.53	26.15 - 21.50
UGI	† UGI CORP	SEP	2.01	1.92	1.67	1.81	1.18	(2.10)	(3.28)	(4.57)	(3.87)	(5.82)	28.87 - 18.69	29.63 - 22.75	29.00 - 20.60	29.98 - 19.20	20.70 - 14.93
WGL	† WGL HOLDINGS INC	SEP	2.35	2.19	1.94	2.13	1.99	20.99	19.89	18.86	18.36	17.54	37.08 - 22.40	35.91 - 29.79	33.55 - 27.04	34.79 - 28.85	31.43 - 26.66
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	2.54	3.78	2.90	0.48	1.86	25.54	24.27	22.81	20.85	22.18	42.37 - 22.80	46.53 - 34.95	39.96 - 27.79	30.58 - 25.56	28.80 - 23.50
AEE	[] AMEREN CORP	DEC	2.88	2.98	2.66	3.13	2.84	28.10	27.47	26.80	25.12	24.90	54.29 - 25.51	55.00 - 47.10	55.24 - 47.96	56.77 - 47.51	50.36 - 40.55
AVA	§ AVISTA CORP	DEC	1.37	0.73	1.49	0.93	0.74	17.58	17.18	17.46	15.87	15.54	23.58 - 15.53	25.81 - 18.19	27.52 - 17.61	20.20 - 16.31	19.43 - 15.35
BKH	† BLACK HILLS CORP	DEC	(1.37)	2.70	2.23	1.09	1.76	17.76	24.32	22.03	20.49	20.37	43.98 - 21.73	45.41 - 35.40	37.95 - 32.46	44.63 - 29.19	32.49 - 26.52
CNP	[] CENTERPOINT ENERGY INC	DEC	1.33	1.25	1.39	0.72	0.67	0.99	0.35	(0.49)	(1.51)	(2.25)	17.35 - 8.48	20.20 - 14.70	16.87 - 11.62	15.14 - 10.55	12.32 - 9.66
CHG	§ CH ENERGY GROUP INC	DEC	2.22	2.70	2.73	2.81	2.69	26.61	26.90	27.44	25.63	24.87	52.36 - 33.39	53.79 - 41.37	54.92 - 44.63	50.23 - 42.07	49.58 - 43.14
CMS	[] CMS ENERGY CORP	DEC	1.29	(0.62)	(0.44)	(0.51)	0.68	10.88	9.46	9.91	10.41	10.51	17.47 - 8.33	19.55 - 14.98	17.00 - 12.09	16.80 - 9.70	10.65 - 7.81
ED	[] CONSOLIDATED EDISON INC	DEC	3.37	3.48	2.96	3.00	2.33	33.91	31.86	29.20	27.78	27.00	49.30 - 34.11	52.90 - 43.10	49.28 - 41.17	49.29 - 41.10	45.59 - 37.23
D	[] DOMINION RESOURCES INC	DEC	3.17	4.15	2.23	1.51	1.92	10.05	9.21	11.44	8.79	10.48	48.50 - 31.26	49.38 - 39.83	42.22 - 34.36	43.49 - 33.26	34.42 - 30.39
DTE	[] DTE ENERGY CO	DEC	3.24	4.64	2.46	3.29	2.56	23.85	23.22	21.00	20.88	19.98	45.34 - 27.82	54.74 - 43.96	49.24 - 38.77	48.31 - 41.39	45.49 - 37.88
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	1.59	2.49	3.51	4.15	4.09	28.22	29.97	28.35	31.55	27.92	53.92 - 36.91	60.63 - 48.10	57.75 - 47.39	60.00 - 47.67	50.53 - 43.50
MDU	† MDU RESOURCES GROUP INC	DEC	1.60	1.77	1.76	1.54	1.18	11.44	11.31	10.49	9.04	8.14	35.34 - 15.50	31.79 - 24.39	27.04 - 21.85	24.75 - 16.99	18.47 - 14.57
NI	[] NISOURCE INC	DEC	1.35	1.14	1.15	1.05	1.63	2.63	3.56	3.29	2.79	2.14	19.82 - 10.35	25.43 - 17.49	24.80 - 19.51	25.50 - 20.44	22.82 - 19.65
NST	† NSTAR	DEC	2.22	2.07	1.94	1.84	1.77	10.95	9.98	14.82 J	8.21	9.52	40.00 - 25.67	37.37 - 30.75	35.90 - 26.50	31.46 - 24.90	27.23 - 22.65
OGE	† OGE ENERGY CORP	DEC	2.50	2.66	2.48	1.84	1.73	20.29	18.31	17.59	14.82	13.86	36.23 - 19.56	41.30 - 29.12	40.58 - 26.34	30.60 - 24.41	26.95 - 22.85
PCG	[] PG&E CORP	DEC	3.32	2.87	2.86	2.43	9.60	25.80	24.00	22.31	21.09	22.00	45.68 - 26.67	52.17 - 42.58	48.17 - 36.25	40.10 - 31.83	34.46 - 25.90
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1.94	2.60	1.50	1.78	1.52	15.22	14.23	12.19	10.78	10.70	52.30 - 22.09	49.88 - 32.16	36.31 - 29.50	34.24 - 24.66	26.32 - 19.05
SCG	[] SCANA CORP	DEC	2.95	2.74	2.63	2.81	2.30	25.81	25.30	24.32	23.28	21.71	44.06 - 27.75	45.49 - 32.93	42.43 - 36.92	43.65 - 36.56	39.71 - 32.82
SRE	[] SEMPRA ENERGY	DEC	4.50	4.34	4.25	3.78	4.03	30.54	31.27	28.02	23.97 J	20.77 J	63.00 - 34.29	66.38 - 50.95	57.35 - 42.90	47.86 - 35.53	37.93 - 29.51
TE	[] TECO ENERGY INC	DEC	0.77	1.91	1.18	1.02	(2.10)	9.15	9.28	7.97	7.36	6.13	21.99 - 10.50	18.58 - 14.84	17.73 - 14.40	19.30 - 14.87	15.49 - 11.30
VVC	† VECTREN CORP	DEC	1.65	1.89	1.44	1.81	1.43	13.72	13.05	12.30	12.32	11.70	32.20 - 19.48	30.50 - 24.85	29.25 - 25.24	29.46 - 25.00	27.09 - 22.86
WEC	[] WISCONSIN ENERGY CORP	DEC	3.06	2.88	2.67	2.59	1.04	24.76	22.72	20.92	19.13	17.53	49.61 - 34.89	50.48 - 41.06	48.70 - 38.16	40.83 - 33.35	34.60 - 29.50
XEL	[] XCEL ENERGY INC	DEC	1.47	1.38	1.39	1.23	1.31	15.35 J	14.70 J	14.28 J	13.37 J	12.99 J	22.90 - 15.32	25.03 - 19.59	23.63 - 17.80	20.19 - 16.50	18.78 - 15.48
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AWR	§ AMERICAN STATES WATER CO	DEC	1.27	1.62	1.34	1.58	1.19	17.68	16.88	15.96	14.92	14.30	42.00 - 27.00	46.14 - 33.57	43.79 - 30.30	34.55 - 24.31	26.80 - 20.82
WTR	† AQUA AMERICA INC	DEC	0.73	0.72	0.70	0.72	0.65	7.52	7.04	6.79	6.12	5.70	22.00 - 12.20	26.62 - 18.86	29.79 - 20.13	29.22 - 17.49	18.48 - 14.18
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	2.07	2.34	1.85	2.14	1.68	11.27	13.41	13.02	12.59	11.15	41.53 - 23.52	43.94 - 31.33	35.40 - 27.40	32.43 - 23.36	24.91 - 18.75

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
J-This amount includes intangibles that cannot be identified.

UTILITY EQUITY THICKNESS REQUIREMENT

Overview

1. The purpose of this evidence is to clearly identify the need for a higher equity thickness in the Ontario Energy Board (the "Board") approved capital structure for the utility. This need results from changes in Enbridge Gas Distribution's current business risk environment and financial risk position. The evidence will show that the utility's business risks have increased since the last time these risks were assessed in EBRO 479 for the 1993 test year. Most importantly, the increased business risk has occurred at the same time as a dramatic decline in the Company's financial strength resulting in: 1) a challenge to the Company's ability to raise term debt when required; and 2) a real risk of a further downgrade in the Company's credit rating.

2. If uncorrected, Enbridge Gas Distribution will not meet its new term debt issue financial covenant based on 2006 forecast results and may be unable to issue new term debt in 2007 based on the current utility allowed equity thickness and return on equity. Furthermore, if the utility's financial integrity is not restored, the Company's credit rating may be downgraded which would cause a number of debt investors to sell their Enbridge Gas Distribution debt holdings in order to avoid breaching the debt holders' investment criteria.

3. Consequently, Enbridge Gas Distribution is requesting an increase in the utility's common equity thickness from 35.0% to 38.0% effective January 1, 2007 to restore the financial integrity of the utility to the level required to enable the Company to sustain access to long term capital on reasonable terms and prudently manage its business risks.

Witnesses: B. Boyle
J. Denomy

4. The Company has provided a “Glossary of Terms” on the final pages of this schedule to facilitate the understanding of the financial terminology.

Equity Thickness History

5. The issue of an appropriate level of equity thickness for Enbridge Gas Distribution was last addressed in front of the Board in the EBRO 479 rate case which set rates for the 1993 test year. The Company argued that it should be allowed to employ an actual equity ratio of 35.51%. The Board’s findings in this instance were as follows:

> The Board notes that the immediate impact of the company’s proposal to employ an actual equity ratio would be an increase in the equity component. The Board finds that such a thickening is not justified by the evidence. The Board, therefore, rejects the proposed use of the company’s 35.51 percent equity as the equity component for ratemaking purposes in the fiscal year. The board deems a common equity ratio of 35 percent to be appropriate for Consumers Gas in fiscal 1993.[1]

6. Table 1 shows the history of Enbridge Gas Distribution’s deemed equity thickness from 1985. Despite a changing business environment, there have been no changes to the Company’s deemed capital structure since the 1987 test year.

[1] Ontario Energy Board, “EBRO 479 Decision With Reasons”, March 3, 1993, pg 91.

Witnesses: B. Boyle
J. Denomy

TABLE 1

Col. 1	Col. 2	Col. 3	Col. 4
Year	Deemed Equity Thickness (%)	Year	Deemed Equity Thickness (%)
1985	37.00	1996	35.00
1986	36.00	1997	35.00
1987	35.00	1998	35.00
1988	35.00	1999	35.00
1989	35.00	2000	35.00
1990	35.00	2001	35.00
1991	35.00	2002	35.00
1992	35.00	2003	35.00
1993	35.00	2004	35.00
1994	35.00	2005	35.00
1995	35.00	2006	35.00

7. There have been material changes to the business environment in which the Company operates since 1993 the last time business risk and an appropriate level of equity thickness was assessed. The Company believes that its business risks have increased significantly and that an increase in the equity component of its deemed capital structure from 35% to 38% is appropriate given the business and financial risks currently faced by the Company. Under the cost of service regulatory framework, equitable rate setting relies on the Company's ability to accurately forecast the revenues generated from distribution and the costs incurred in providing distribution services. Increased volatility in the underlying drivers of gas consumption puts the Company at risk of greater forecasting error. Given the Company's current financial risk position, any large deviations between actual and forecast revenues or costs will have an impact on the Company's earnings and

possibly its credit rating and access to capital. Paragraphs 11 to 27 discuss the business risks faced by the Company.

Business Risks

8. Business risk is affected by volatility in a firm's operating earnings due to the risk inherent in a firm's underlying operations. These risks are a result of uncertainty in demand for a firm's products, and the firm's ability to ensure products are priced to recover the costs incurred in the production or provision of services. In the absence of any debt financing in a firm's capital structure only the shareholder faces the business risk. Once debt financing is introduced into a firm's capital structure the firm becomes leveraged and must be able to meet the fixed charges and debt covenants required by lenders. Leverage introduces the concept of financial risk into the risk profile faced by equity holders.

9. Capital structure, the amount of debt and equity used to finance a firm, is a function of the amount of business risk faced by the firm. Volatility in earnings is one of the drivers of higher business risk. Higher levels of business risk will generally require a higher level of equity in a firm's capital structure such that fixed charges and debt covenants stemming from financial leverage are adequately covered. Conversely, lower levels of business risk will support a lower level of equity financing as the risk of not meeting fixed charge obligations and covenants is less.

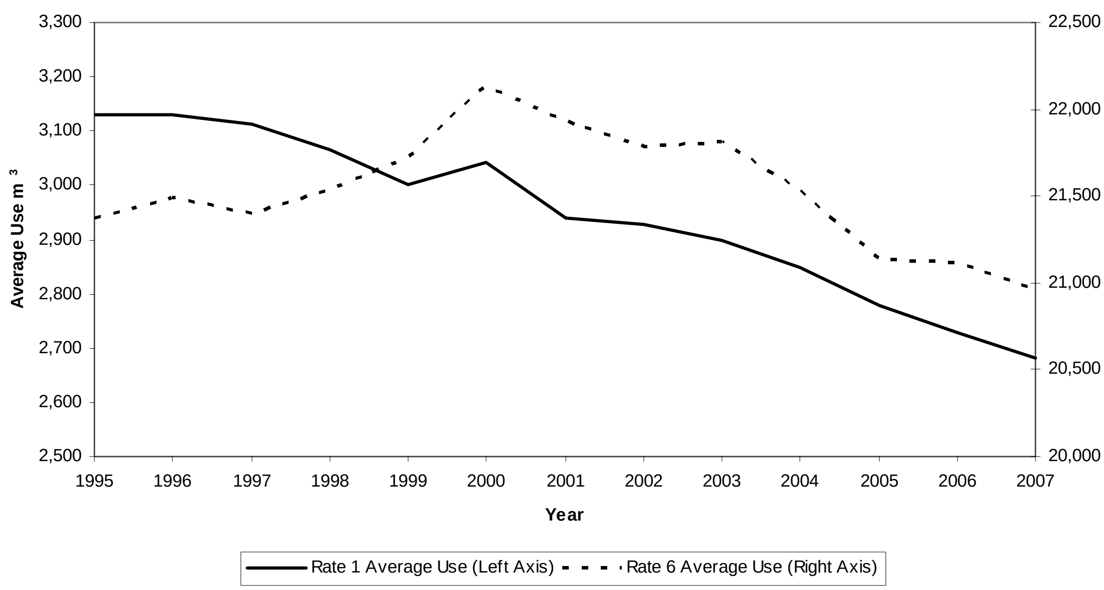
10. For a gas distribution utility, business risk ultimately relates to the utility's ability to recover its investment in its assets or rate base, while at the same time achieving its allowed return on equity and maintaining a sufficient level of protection to meet fixed charges and debt covenants. Significant factors that affect the level of business risk faced by a gas distribution utility are the price of natural gas and alternative energy

forms, the dynamics of its customer base, the regulatory environment, forecast risks and the general economic environment in which the utility conducts business.

a. Volumetric Risks

11. General service average use has been declining since the early 1990's. Figure 5 shows average use for Rate 1 and Rate 6 normalized to 2007 budget degree days. On average, Rate 1 average use has declined by 1.2% per year since 1995 and Rate 6 average use has declined by 0.1% per year since 1995. Since 2001, Rate 1 average use has declined by 1.8% on average and Rate 6 average use has declined by 0.9% on average.

Figure 5



12. The decline in average use is a result of a combination of factors such as higher and more volatile gas prices, self imposed and government imposed conservation in light of higher energy costs and environmental concerns, and changes in the

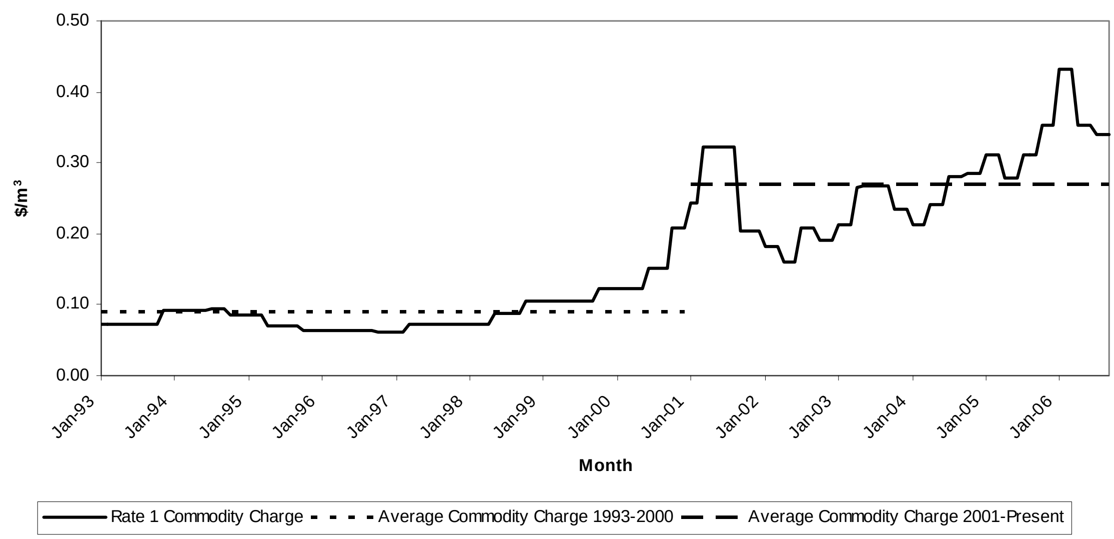
Witnesses: B. Boyle
J. Denomy

customer and housing/building stock. Increased volatility in the underlying drivers of gas consumption puts the Company at risk of greater forecasting error for gas consumption. Given the Company's current financial risk position, any large deviations between actual and forecast volumes will have an impact on the Company's earnings and possibly its credit rating and access to capital.

b. Natural Gas Prices Increases and Volatility

13. From 1993 until 2000, natural gas commodity prices remained relatively stable and showed little volatility. Since then, natural gas commodity prices have become more volatile and increased dramatically. Figure 1[2] shows the system sales gas supply charge per cubic meter for Rate 1 (residential) customers.

Figure 1



[2] The averages shown in Figure 1 and calculated in Table 2 and the standard deviations calculated in Table 3 are calculated using monthly data from January 1993 to December 2000 and January 2001 to September 2006 for the 1993-2000 and 2001-Present periods respectively. Calculations are inclusive of September 2006 system sales gas commodity charges as these are the most recent actual commodity charges known at the time this evidence was written.

Witnesses: B. Boyle
J. Denomy

14. It is clear from Figure 1 that natural gas commodity costs have increased dramatically since 2000. Table 2 shows the average system sales gas supply charge from 1993 to 2000 and 2001 to the present. The average system sales gas supply charge has increased 198% over the two time periods.

TABLE 2

Col. 1	Col. 2
Average 1993-2000 ($/m^3)	0.090
Average 2001-Present ($/m^3)	0.269
% Change	198.29%

15. In addition to an upward trend in price, commodity price volatility has increased dramatically since 1993 as well. Table 3 shows the standard deviation[3], a measure of volatility, of the Rate 1 system sales gas supply charge from 1993 to 2000 and 2001 to the present. The standard deviation of the system sales gas supply charge has increased 116% over the two time periods.

TABLE 3

Col. 1	Col. 2
Standard Deviation 1993-2000 ($/m^3)	0.031
Standard Deviation 2001-Present ($/m^3)	0.066
% Change	115.67%

[3] Standard deviation is calculated as: $StDev = \sqrt{\dfrac{\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2}{n-1}}$.

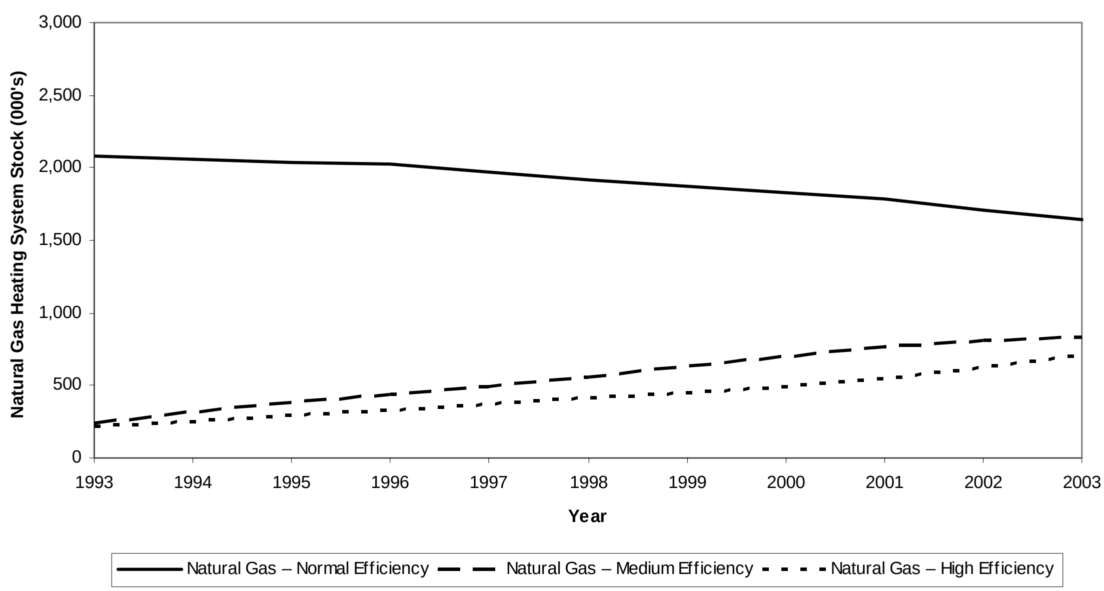
Witnesses: B. Boyle
J. Denomy

16. Increasing energy costs and energy price volatility ultimately cause customers to conserve and reduce energy consumption. Periods of increasing prices and price volatility result in a large range of price changes which can occur over short periods of time. The end result is self induced conservation efforts on the part of utility customers which ultimately result in reduced natural gas consumption and therefore earnings.

c. Natural Gas Appliance Use

17. Natural gas remains the primary source of energy for space heating for the Company's residential customer sector. However, the incidence of medium and high-efficiency natural gas furnace usage has been increasing. Figure 2 shows the natural gas heating system stock by efficiency type for Ontario.

Figure 2



Witnesses: B. Boyle
J. Denomy

18. In 1993 medium and high efficiency furnaces made up 9% of the overall natural gas furnace market in Ontario. In 2003 medium and high efficiency furnaces comprised 48% of the natural gas furnace market in Ontario. As building code regulations on new home energy efficiency become more stringent, the trend towards medium and high efficiency furnace installation will continue. Replacement of older less efficient appliances with new, more efficient appliances will reduce gas consumption for existing customers. Furthermore, builder specifications for non-gas appliances represent a risk to the extent that new customers may be influenced to purchase non-gas appliances for their homes due to builder specifications.

19. These factors are contributors to a declining average use per customer.

d. Customer Dynamics

20. The housing market in Ontario has experienced dramatic growth over the past few years. There has been a trend toward the construction of multiple, rather than single detached homes. Semi-detached and town-homes are typically smaller than single family dwellings. Lower square footage reduces the space requiring heating resulting in lower consumed volumes for new customers. Figure 3 shows single versus multiple housing starts within the Greater Toronto Area ("GTA").

Witnesses: B. Boyle
J. Denomy

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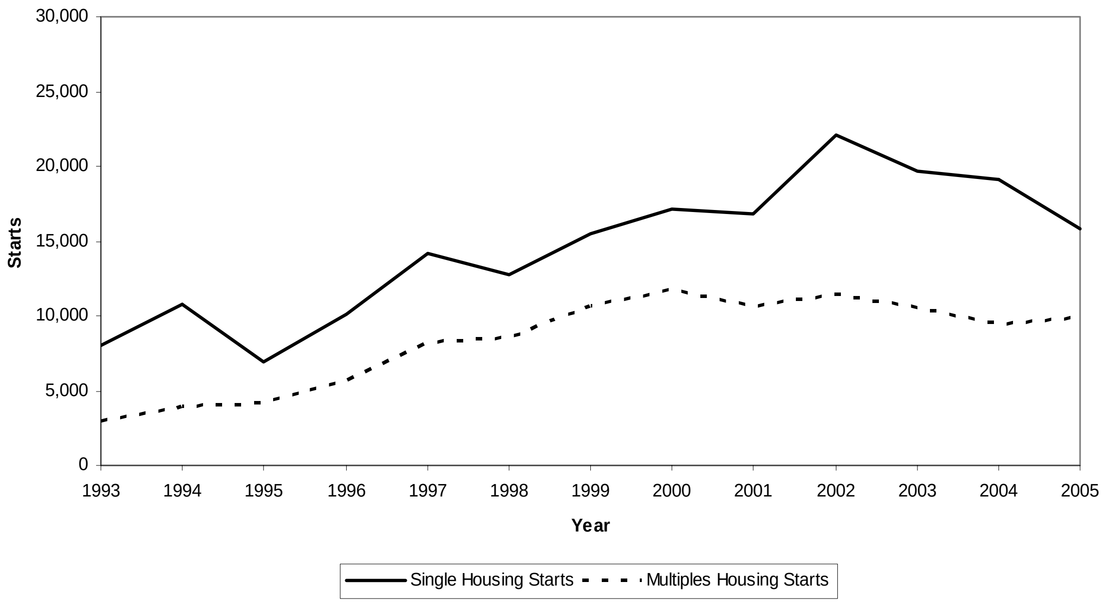
Figure 3

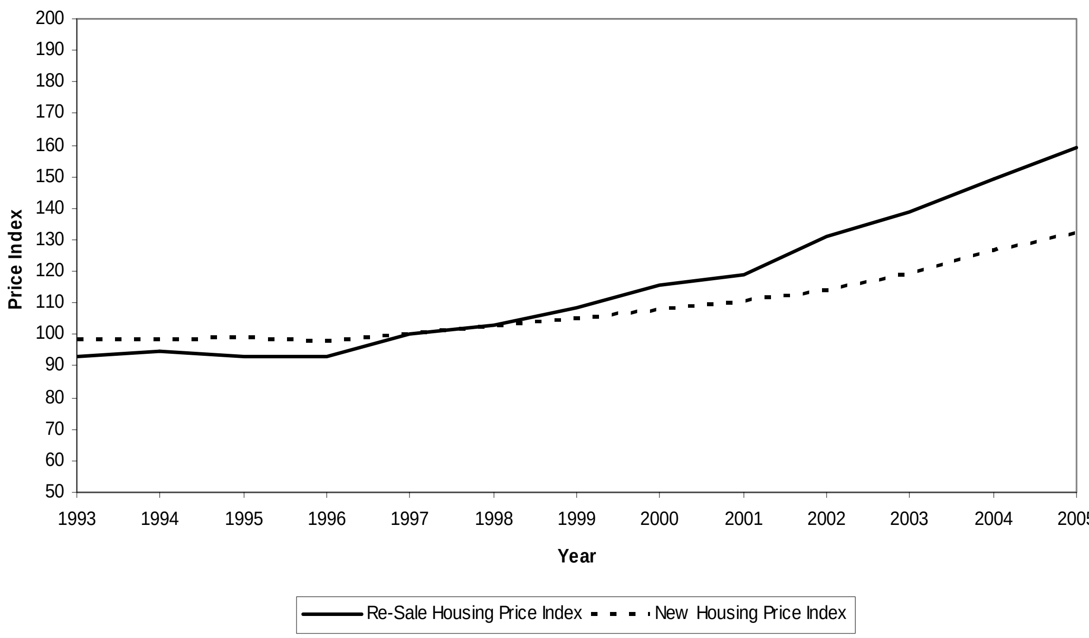


21. In addition to an increase in multiple housing starts, housing prices in general have increased dramatically across the Enbridge Gas Distribution franchise area. Figure 4 shows a price index[4] for new and re-sale homes in the GTA.

[4] 1997=100

Witnesses: B. Boyle
J. Denomy

Figure 4



22. Higher prices for new and pre-owned homes make the purchase of new semi-detached or town-homes relatively more affordable. A preference for smaller, more affordable multiple homes will likely cause further growth in this housing type and a related reduction in average gas consumption.

e. Regulatory and Legislative Environment

23. As outlined above, business risk results from uncertainty in the Company's ability to sell its product and in its ability to price its product to recover costs. A regulated entity's ability to forecast and recover costs is strongly influenced by its regulatory environment. The regulatory environment has seen a significant increase in the number of intervenors and proceedings over the past few years. Enbridge Gas Distribution is of the opinion that these factors in conjunction with forthcoming

Witnesses: B. Boyle
J. Denomy

proceedings increase uncertainty with respect to forecasting costs and recovering them.

24. Ontario gas utilities are in the midst of several proceedings under the Natural Gas forum umbrella which are expected to re-define the regulatory environment and create uncertainty, at least until their resolution. These include the Natural Gas Electricity Interface Review proceeding that contemplates regulatory changes to the natural gas storage environment in Ontario, the addition of a significant new natural gas market through gas fired generation and unbundling of services. Proceedings to establish an Incentive Regulation Framework and various other processes to review cost allocation issues, long term contracting and QRAM methodology are other components of the Natural Gas Forum. Other processes that create uncertainty with respect to the operating environment include GDAR. Recent decisions with respect to allowing the first physical bypass of the natural gas distribution system in Ontario (Greenfields Energy Centre ("GEC") RP-2005-0022, EB-2005-0441, EB-2005-0442, EB-2005-0443, EB-2005-0473) and treatment of the proceeds from sale of investor owned assets (cushion gas) add to uncertainty.

25. Taken together, the proceedings described above affect every facet of the Company's operating environment. The GEC Decision sets a new precedent with respect to the interpretation of franchise rights. GDAR and unbundling of rates and services affect market segments where the regulated entity participates with competitive entities. These proceedings impose costs on the regulated entity to facilitate competition, while at the same time subjecting the utility to uncertainty about cost recovery through the subsequent exercise of choice by customers. Uncertainty with respect to cost recovery of upstream gas costs to serve currently

bundled customers is particularly important given that these costs are a large multiple of the Company's earnings. Finally, the Company welcomes the opportunity to participate in a process leading to lighter handed incentive regulation, which could reduce regulatory risk by reducing the number of proceedings and interventions. On the other hand, a new framework that does not explicitly recognize declining average use, the need to incur significant capital expenditures, coupled with the other industry changes described above could increase regulatory risk.

26. The Company faces further uncertainty due to the recent decision by the Canadian Accounting Standards Board to adopt a strategic plan that calls for convergence of Canadian Generally Accepted Accounting Principles with International Financial Reporting Standards over a five year period as outlined at Exhibit A1, Tab 6, Schedule 2. This development will potentially result in the removal of certain exemptions currently applicable to the accounting ~~of~~ for rate regulated entities. The accounting principles that are currently applied to the Company's financial statements allow for congruence between the actions of the regulator in the rate setting process and their consequential impacts on revenue, expense and earnings recognition as well as on the creation of assets and liabilities. This congruence will be diminished as a result of these forthcoming changes.

27. The Company faces federal and provincial legislative risk as well. The Ontario government is now set to implement the highest energy efficiency standards in Canada under new building code provisions.[5] All homes built in and after 2012 will have to meet EnerGuide 80 standards. Changes to the Ontario building code will be phased in by the Ministry of Municipal Affairs and Housing beginning next year. Depending on the nature of the incentive regulation framework to be introduced for

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[5] Ministry of Municipal Affairs and Housing, "New 2006 Building Code", June 2006

2008, the Company may be at risk of further declines in average use over the period of the incentive regulation framework due to the phase in of these new guidelines.

f. Credit Rating Risk

28. General economic conditions can have a significant impact on the volumes consumed by EGD's customers. Structural breaks in the economy, for example, SARS and the August Blackout, are unavoidable. The impacts of events such as these can have a negative impact on volume consumption. Should other one time events such as these occur in the future, the Company may be at risk of a credit downgrade. Dominion Bond Rating Service (DBRS) recently noted in a presentation dated May 2003 that:

> …Canadian utilities have less 'safety margin' than U.S., and are vulnerable to a quick downgrade if something goes wrong.[6]

Coverage ratios for the Company have significantly deteriorated since 1993 as shown in Table 4 presented later in this evidence. A sudden structural break and substantial loss in volumes either currently or prospectively could reduce earnings and result in a quick credit downgrade given the current financial risks faced by the Company.

Capital Structure Overview

29. The Company's evidence above describes the changes in the business and operating environment since the utility's equity thickness was last reviewed by the Board for the 1993 Test Year. In particular, the volatility in natural gas prices that has developed over the past 5 to10 years has had extensive material impacts on a

[6] Dominion Bond Rating Service, "The Rating Process and Cost of Capital for Utilities", May 2003

number of aspects of the utility business. These include the variability in customer demand due to conservation and competitive risks of fuel switching, the impact on short term liquidity requirements for the utility, and a weaker credit profile for the utility business due to the overall increase in business risks. The business risks and equity thickness analysis in this evidence and the Company's application are based on the current forecast test year cost of service regulatory environment that applies to the utility and may find the need for further review in an incentive rate environment.

30. It is important to note that a company's business risks must be taken into account when a company establishes its target capital structure and, in particular, its equity thickness which has a direct impact on the financial integrity of the company. The reason for this is that as a utility providing an important infrastructure service, a utility must maintain a strong capital attraction standard to have ready access to financial markets in all stages of a business cycle to meet its capital needs and customer service obligations. If the utility's access to capital markets is constrained, its financial integrity would be in jeopardy and it may not be able to provide the essential services to its customers.

31. As a simple overview, a company's target capital structure is an appropriate mix of debt and equity. The reason for this analysis starts with the fact that debt investors are given a legal priority in payment of interest and principal over payments to equity holders, but typically receive a lower return than equity investors in exchange for this priority of payment. However, there is no specific mathematical formula to dictate a precise mix of each type of capital that would be appropriate for any particular company. In addition, there are "hybrid" types of capital, such as

preferred shares and subordinated debt, that have debt like features as well as some equity like features and in some cases may also be an appropriate form of capital to include in a company's target capital structure.

32. Theoretically, there are an infinite number of permutations or combinations of capital that a company could chose to manage its financial risk. In practice, financial markets have established a relatively narrow range of the proper mix of debt and equity for a given industry, with company specific factors influencing the location for a specific entity within the industry range. In order to achieve the desired balance of debt and equity, the most important factor is the nature of the company's business risks and how much volatility and uncertainty is associated with these risks and the magnitude of their impact on the company's earnings.

33. In simple terms, a company with significant business risks will have greater earnings volatility and require a correspondingly higher level of equity. The reason for this is that a higher risk company will have more difficulty in attracting capital, particularly debt investors who may not receive their interest income when earnings are low. If the volatile market conditions lead to a longer period of low earnings, the company will run out of cash or liquidity to pay not only the debt investors' interest, but also, in severe cases, their principal repayment may be jeopardized and the company could be forced into bankruptcy.

34. On the other hand, a company with a very stable and predictable earnings level will usually have very few material business risks and be able to support a higher level of debt in its capital structure. In this case, debt investors are relatively confident that they will receive regular interest payments with little principal repayment risk. Most regulated utilities are in this category and typically have a relatively high

proportion of debt in the capital structure compared to other industries, which ultimately benefits rate payers through a lower total cost of capital.

35. In summary, a company's business risks combined with a company's financial risks to establish the total investment risk. The total investment risk is used to determine the capital structure weightings to provide the required financial integrity and capital attraction standards appropriate for a particular company. This assumes that the costs of each of these capital types are appropriately established by the market (or regulator) for investments of similar overall business and financial risk.

Credit Ratings

36. While this is a very high level view of how a company establishes a target capital structure, there are a number of other factors that are assessed by the market and ultimately lead to a rating of a company's financial strength. A detailed credit analysis is a complex combination of quantitative and qualitative measures that are evaluated and weighted to assign a credit rating for a particular company. However, the one of the most important factors that will impact a company's credit assessment is the capital structure. Moreover, as this is something that a company's management has control over, management can control to a significant degree the company's credit quality and access to capital. In the case of Enbridge Gas Distribution, it has obtained credit ratings from two agencies that specialize in evaluating the credit quality of debt issuers, DBRS and Standard and Poor's ("S&P"). Enbridge Gas Distribution is currently assigned a credit rating of "A" by DBRS and "A-"(A minus) by S&P. The credit rating reports on Enbridge Gas Distribution by these agencies and their rating scales are filed at Exhibit A3, Tab 8, Schedule 1.

37. As noted above, a credit analysis involves an assessment of a number of financial metrics, such as debt to total capital ratio ("Debt to Total Capital"), and Earnings Before payment of Interest expense and income Taxes interest coverage ("EBIT Interest Coverage"). This last ratio is defined as a company's Earnings Before payment of Interest expense and Income taxes (often referred to as "EBIT"), divided by the company's interest expense.

38. The EBIT Interest Coverage ratio is extremely important because it is an indication of how much of an "error margin" debt investors see in the company's net operating earnings before the company will be unable to pay its interest expense.

39. Table 4 below shows the Enbridge Gas Distribution Ontario utility EBIT Interest Coverage ratio based on the allowed capital structure and costs of capital from the Board decision since 1993. As these are all based on normal weather, they represent normalized coverage ratios. The derivation of the figures presented in Table 4 is provided in Appendix 1 and is described in detail in the "Explanatory Notes" material provided for Appendix 1.

Witnesses: B. Boyle
J. Denomy

TABLE 4

Col. 1	Col. 2	Col. 3	Col. 4
	Test Year	Normalized Allowed Utility EBIT Interest Coverage Per Board Decision (times interest coverage)	EBIT Margin Above 2 Times Coverage ($ Millions)
1.	1993	2.38	48.0
2.	1994	2.33	43.7
3.	1995	2.34	47.4
4.	1996	2.37	55.7
5.	1997	2.36	57.5
6.	1998	2.30	48.2
7.	1999	2.23	38.6
8.	2000	2.23	33.2
9.	2001	2.20	32.0
10.	2002	2.24	33.6
11.	2003	2.18	27.5
12.	2004*	NA	NA
13.	2005	2.19	29.8
14.	2006	2.10	16.8

* Due to the nature of the application for the 2004 test year (rates were escalated) there is no Board approved capital structure for this year.

40. The table clearly identifies the alarming decline in the EBIT Interest Coverage ratios from 1993, which is the last time the Company's equity thickness was specifically reviewed by the Board, the utility's financial strength has weakened considerably leaving very little "margin of error" for actual results relative to forecast. Not surprisingly, during this period both credit rating agencies have downgraded the credit rating of Enbridge Gas Distribution. DBRS first downgraded the Company from "A (high)" to "A" in January 2001 and S&P followed in December of 2001 with a downgrade from "A" to "A-"(A minus). The rationale for the downgrades was clearly

Witnesses: B. Boyle
J. Denomy

linked to the increased business risks and weaker financial ratios as noted by DBRS in their January 9, 2001 press release as follows:

> DBRS is downgrading The Consumers' Gas Company Ltd.'s commercial paper rating to R-1 (low), long-term debt rating to "A" and preferred share credit rating to Pfd-2, with Stable trends, from R-1 (middle), A (high) and Pfd-2 (high), respectively. The ratings adjustments are based on the following considerations. Earnings volatility from traditional business risks such as weather and economic conditions has increased as a percentage of base earnings following the transfer of ancillary businesses to affiliates during F2000 and due to a decline in approved ROEs over the last 5 years. The steady decline in approved ROEs, consistent with the trend in long-term interest rates, has adversely affected earnings over the period. These factors, in combination, have resulted in a decline in certain key financial ratios from weather normalized historical highs. An expected slowdown in the Canadian economy could potentially lead to a further decline in interest rates and approved ROEs. While working capital needs have increased recently due to a very sharp increase in the cost of natural gas inventories that are generally financed with short-term debt, DBRS expects little material change in balance sheet leverage given the nature of the industry. The Company's primary challenge remains its earnings sensitivity to weather, given that roughly 70%-75% of distribution volumes are delivered to temperature sensitive residential and commercial customers. While the forecasting methodology adjusts for variations so that the earnings impact is moderated over a 5-year period, temperature variability can contribute to material short-term earnings volatility and can significantly affect key financial ratios. The Company's long-term outlook remains favourable, given one of the most attractive business franchises in Canada characterized by strong economic fundamentals.

41. Despite the decline in interest rates over the past five years, the utility’s financial ratios, earnings volatility, and overall credit quality have continued to deteriorate such that the Company is at significant risk of a further and more serious credit rating downgrade. If S&P were to downgrade Enbridge Gas Distribution, the utility would fall into the “BBB” (triple B) category.

42. This is significant because many investors or investment funds have investment criteria that prohibit or limit the ownership of any debt with a rating below the “A” category. This would cause an immediate sale of the Company’s outstanding debt held by such institutions and would lead to a significant reduction in Enbridge Gas Distribution’s access to capital and increase the cost of borrowing.

Witnesses: B. Boyle
J. Denomy

43. Although sufficient access to capital would probably still be available in the strong segment of an economic cycle, this access would certainly be constrained in the weaker segments of a full economic cycle.

44. Restricted access to capital would result in increased borrowing cost, which can be estimated by referencing corporate borrowing spreads for BBB rated credits (currently about 10 to 20 basis points or 0.10% to 0.20% in higher annual interest rates for a 10 year medium term note, but can be much higher when capital market conditions are weak).

45. Furthermore, the reduced access to capital could reasonably lead to constraints on the Company's ability to add customers and meet service obligations. Moreover, once a credit rating has slipped below the "A" level, it is very difficult to recover that drop.

Financial Covenants and Trust Indenture

46. Each time Enbridge Gas Distribution issues term debt, it enters into a contract with the purchasers, or "holders", of the new debt. This contract, referred to as a trust indenture, contains a number of conditions that each of the parties must abide by as long as the debt is outstanding. The trust indenture can be different for each specific debt issue and every debt issuer will have different obligations depending on the credit quality of the company and the market conditions at the time of the issuance. Enbridge Gas Distribution enjoys relatively favourable terms in its current trust indenture due to its "A" category credit rating and has been able to use a similar trust indenture for all of its outstanding term debt.

Witnesses: B. Boyle
J. Denomy

47. Generally, the most significant obligations for an issuer in its trust indenture are the financial obligations, or “covenants”, that the issuer agrees to abide by until it repays the debt. For Enbridge Gas Distribution, its most stringent financial covenant is a “new issue” test contained in Section 5.04, paragraph (5). Under this covenant, the Company has agreed that it will not issue any term debt (defined as debt with a maturity date of 18 months or more after the date of issue of the debt) unless the Company’s consolidated net earnings before interest expense and income taxes (similar to EBIT) shall have been at least two times the long term debt interest expense for any twelve consecutive months out of the last twenty-three months. This calculation is essentially equivalent to the Company’s EBIT Interest Coverage ratio.

48. The rationale for the interest coverage financial test is that it gives the debt investors some comfort that the Company will not take on additional debt when its financial performance deteriorates to a level that puts the interest payment at risk. The reason for the “twelve consecutive out of the last twenty-three month” allowance in the test is to provide some leeway in case of a one-time material unfavourable event.

49. As the Company’s credit position has weakened since the last equity thickness review, its “margin of error” from business risk volatility in its actual earnings compared to forecast earnings to still meet the new issue interest coverage financial covenant has decreased dramatically as shown in Table 4. This demonstrates clearly that the Company’s access to capital is much more likely to be constrained than at any time in its history.

Witnesses: B. Boyle
J. Denomy

50. In fact, based on actual weather for the first quarter of 2006 which reduced earnings before interest expense and income taxes (EBIT) by $33.3 million, Enbridge Gas Distribution will not meet the new issue test covenant for any twelve month period that includes January 2006 to March 2006. Without a change to the utility's capital structure for Fiscal 2007, an unfavourable reduction in forecast EBIT of $16.8 million or more in 2007 will prevent Enbridge Gas Distribution from having open access to the long term debt market.

51. The business risks such as lower than expected average uses, large volume customer fuel switching or plant closures, are overshadowed by weather, the greatest and most volatile risk for the utility. The impact of weather on the utility's EBIT since 1993 is shown in Table 5 below:

TABLE 5

Col. 1	Col. 2	Col. 3	Col. 4
	Test Year	Impact of Actual vs Forecast Weather on Utility Earnings Before Interest Expense and Income Taxes* ($ Millions)	Absolute Value of Weather Impact on EBIT ($ Millions)
1.	1993	10.6	10.6
2.	1994	30.1	30.1
3.	1995	(30.1)	30.1
4.	1996	29.6	29.6
5.	1997	2.3	2.3
6.	1998	(70.0)	70.0
7.	1999	(55.0)	55.0
8.	2000	(38.9)	38.9
9.	2001	8.5	8.5
10.	2002	(47.3)	47.3
11.	2003	72.0	72.0
12.	2004	37.5	37.5
13.	2005	0.0	0.0
14.	2006 Q1	(57.7)	57.7
15.	Total	(107.4)	
16.	Average	(7.7)	35.0

* A positive number indicates colder than forecast weather and higher than forecast earnings and a negative number (bracketed and bolded) indicates warmer than forecast weather and lower than forecast earnings.

52. Since 1993, the average annual impact of weather on the utility's EBIT on an absolute value basis has been $35.0 million, significantly higher than the $16.8 million error margin reflected in the 2006 rates. Also of note is the fact that while there has been a roughly equal number of "colder than forecast" and "warmer

than forecast" years, the cumulative impact of weather since 1993 has been a reduction of over $107 million in utility EBIT due to actual weather being warmer than forecast weather.

Requested Equity Thickness

53. Based on:

a) the increased business and financial risks that have developed for Enbridge Gas Distribution over the last 10 to15 years described in this evidence and at Exhibit E2, Tab 1, Schedule 2,
b) the foreseeable challenge to issuing new long term debt; and
c) the looming risk of a credit rating downgrade, the Company believes that the utility's capital structure must be adjusted to increase the deemed equity ratio from 35.0% to 38.0%.

54. The justification for the 38.0% level is the utility's critical need to maintain a capital attraction standard that provides access to term debt markets at all stages of an economic cycle, in order to ensure that the utility's customers have the capital needed for the projects they require, at the best possible cost.

55. In order to continue to benefit from this open access, the utility must maintain its "A" credit rating and must be able to meet its new issue trust indenture covenant. At a 35.0% deemed equity ratio and current interest rates, Enbridge Gas Distribution does not have an adequate "margin of error" in actual versus forecast earnings to have reasonable confidence in meeting its new issue test covenant and is at risk for further credit rating downgrades.

56. Enbridge Gas Distribution believes that in the current business risk and financial market environment, it must have an EBIT interest coverage of at least 2.2 times to provide adequate room for weather and normal business volatility and be able to

maintain its credit strength and capital market access throughout a business cycle. The Company's requested deemed equity ratio of 38.0% just achieves this minimum target as shown in Table 6 below and thus is an appropriate level for the utility to maintain at this time.

TABLE 6

Item No.	Approved Equity Thickness	EBIT Interest Coverage Ratio (times)	EBIT Margin Above 2 Times Coverage ($MM)	Change in Requested Deficiency ($MM)
1 – Company Requested	38%	2.23	38.1	$0.0
2 – Scenario A	37%	2.18	31.0	($3.6)
3 – Scenario B	36%	2.14	23.9	($5.9)
4 – Scenario C	35%	2.10	16.8	($9.5)

Comparison to Other Canadian Utilities

57. Enbridge Gas Distribution is a relatively large local gas distribution utility with a premium franchise territory and a diversified customer base. Its capital structure, business risk, financial risk, trust indenture covenants and credit profile are specific to the Company and are appropriately measured and analyzed on a standalone basis. Nonetheless, it is helpful to understand how Enbridge Gas Distribution's financial position compares to other premier Canadian utilities and industry trends.

58. The Company notes that TransCanada Pipelines Ltd. had its deemed equity thickness increased from 30.0% to 33.0% effective January 1, 2001 by the National Energy Board in its RH-4-2001 Decision and further increased from 33.0% to 36.0%

Witnesses: B. Boyle
J. Denomy

in the RH-2-2004 Decision effective January 1, 2004. In addition, the British Columbia Utilities Commission approved an increase in equity thickness for Terasen Gas Inc. from 33.0% to 35.0% effective January 1, 2006 in its G-14-06 Decision. Enbridge Gas Distribution believes that a direct comparison of its business and financial risks and resulting capital structure relative to these utilities is ultimately not relevant due to the unique and specific capital structure needs of the Company that must be determined in this application. However, the Company does believe that this information is helpful to provide context for the general direction and industry trends with respect to Canadian utility capital structures.

59. The Company is aware that Union Gas has recently agreed in their 2007 rate application (EB-2005-0520) to a utility deemed common equity thickness increase from 35.0% to 36.0%. The Company is also aware that Union's agreement to the 36% equity thickness was part of a comprehensive financial package regarding financial matters and that there were compromises made by all parties in order to reach this agreement on all the financial issues. However, based on the 36.0% equity thickness and Union Gas' normalized cost of capital forecast, Union Gas indicated that it does not expect to meet its new term debt issue financial covenant in 2007 and will rely on short term debt capital or possibly the use of a preferred share issue to meet its funding needs during this period (EB-2005-0520 Tr. Volume 1, pp 18, lines 10 to 15). Enbridge Gas Distribution recognizes that this funding approach can be done for a temporary period in a strong corporate credit environment which the capital markets are experiencing in mid-2006. However, Enbridge Gas Distribution believes that it is more prudent and cost effective to fund long term utility assets with long term capital. The use of short term capital to fund long term utility assets is not a sustainable financing strategy for such assets and issuing preferred shares would likely burden ratepayers with higher costs in future

years. Enbridge Gas Distribution believes that the core financial integrity issue must be addressed and that it is most appropriate to address the issue before any of the adverse risks develop that could increase the cost of restoring the utility's financial integrity.

Conclusion

60. Enbridge Gas Distribution's business risks have increased have its financial integrity has declined over the last few years to the point where the Company is in jeopardy of losing its open access to long term capital markets and its credit rating may be downgraded. This would cause a restriction in access to capital to fund needed utility facility enhancement, and lead to an increase the utility's cost of capital, and a related increase in the rates charged to customers. Consequently, Enbridge Gas Distribution is requesting an increase in the utility's common equity thickness from 35.0% to 38.0% effective January 1, 2007 to restore the financial integrity of the utility to the level required to enable the Company to sustain access to long term capital on reasonable terms and prudently manage its business risks.

Witnesses: B. Boyle
J. Denomy

Glossary of Terms

Basis Point	One-hundredth of a percentage point, used in reference to interest rates or rates of return on equity
Bond Rating	A quality rating assigned by credit rating agencies as an indication of creditworthiness
Business Risk	The risk attributed to the nature of a particular business activity (as distinct from financial risk). For pipelines, it typically includes supply, market, regulatory, competitive, and operating risks
Capital Attraction Standard	The aspect of the fair return standard that requires that the return of a regulated utility permit incremental capital to be attracted to the enterprise on reasonable terms and conditions
Capital Structure	The way in which a business is financed; generally expressed as a percentage breakdown of the types of capital employed
Cost of Service	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Covenant	A specific obligation imposed by contract on a party
Deemed Capital Structure	A notional capital structure used for rate-making purposes that may differ from a company's actual capital structure
EBIT	A financial measure equal to the earnings before interest expense and income taxes of a business
EBIT Interest Coverage	The number of times that earnings for a given year, before interest expense and income taxes, covers the annual interest expense
Embedded Cost of Debt	The weighted-average historical cost of long-term debt outstanding

Witnesses: B. Boyle
J. Denomy

Fair Return Standard	A standard that should be examined when setting the return allowed to a company; it is comprised of the comparable investment, financial integrity and capital attraction standards
FFO Interest Coverage	A financial ratio calculated as the funds from operations over gross interest incurred before subtracting capitalized interest and interest income
FFO to Total Debt Ratio	A financial ratio calculated as the funds from operations over long term debt (including amount for operating lease debt equivalent) plus current maturities, commercial paper and other short-term borrowings
Financial Integrity Standard	The aspect of the fair return standard that requires that the return of a regulated utility enable the financial integrity of the regulated enterprise to be maintained
Financial Risk	The risk inherent in a company's capital structure; financial risk increases as the proportion of debt increases in relation to shareholders' equity
Funds from Operations (FFO)	The net income from a company's continuing operations plus depreciation, amortization, deferred income taxes, non-cash items, and interest expense
Investment Risk	The total of a company's business risk and financial risk
Market Risk	The business risk that stems from the overall size of the market and the market share that a pipeline is able to capture
Operating Risk	The risk to the income-earning capability that arises from technical and operational factors
Pro Forma	Describes a presentation of data, typically financial statements, where the data reflects the world on an 'as if' basis; for example, financial statements that are adjusted to reflect a projected transaction

Witnesses: B. Boyle
J. Denomy

Rate Base	The amount of investment on which a return is authorized to be earned; it typically includes plant in service plus an allowance for working capital
Regulatory Risk	The risk to the income-earning capability of the assets that arises due to the method of regulation of the company
Revenue Requirement	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Supply Risk	The risk that the physical availability of natural gas could affect a utility's income-earning capability
Trust Indenture	A contract between an issuer of debt and the holder of the debt with the terms and conditions of the contract monitored by a trustee

Witnesses: B. Boyle
J. Denomy

CME, CCC, SEC, VECC INTERROGATORY #4

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 1, Schedule 2, Testimony of R. Fischer et al

EGDI Peers at pages 8 to 12

a) Please provide a table containing all S&P’s current bond ratings for US regulated gas and electric utilities along with their business risk designation.

b) Please confirm that the median bond rating for US gas and electric utilities rated “excellent” in terms of their business risk profile is BBB, while that in Canada is A.

RESPONSE

a) The most recent S&P Issuer Ranking report for U.S. Regulated Utilities (water utilities were disregarded for the purposes of this analysis), which also includes the business risk designation for each utility, has been provided as Attachment A.

b) According to the most recent S&P Issuer Ranking report, the median bond rating for US gas and electric utilities rated “excellent” in terms of their business risk profile is BBB+, not BBB. The median rating for natural gas utilities is A-. In the most recent S&P Issuer Ranking report for Canadian Gas and Electric Utility Companies, the median bond rating for companies rated “excellent” in terms of business risk is A. Please see Attachment A for the most recent S&P Issuer Ranking reports for U.S. Regulated Electric and Natural Gas Utilities. The most recent S&P Issuer Ranking report for Canadian Gas and Electric Utility Companies has been provided as Attachment B.

Witnesses: J. Coyne
J. Lieberman
Concentric

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue E2
Schedule 21.4
Attachment A

STANDARD
&POOR'S

Global Credit Portal®
RatingsDirect®

April 20, 2012

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

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Issuer Ranking:

U.S. Regulated Utilities, Strongest To Weakest

The following list ranks all the rated companies in the U.S. regulated electric, gas, and water utility sectors from strongest to weakest based on rating and outlook. We further rank companies with the same rating and outlook 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 cards, see "Industry Report Card: U.S. Regulated Electric Utilities Remains Stable," published on March 28, 2012 and "Industry Report Card: U.S. Regulated Gas And Water Utilities' Credit Quality Should Remain Steady in 2012," published on April 12, 2012.

U.S. Regulated Utilities

	Corporate credit rating*	Business profile	Financial profile	Liquidity
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Intermediate	Adequate
Midwest Independent Transmission System Operator Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
Aqua Pennsylvania Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
Washington Gas Light Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
WGL Holdings Inc.	A+/Stable/A-1	Excellent	Intermediate	Adequate
The Baton Rouge Water Works Co.	A+/Stable/--	Excellent	Intermediate	Strong
American States Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Golden State Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Northwest Natural Gas Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
California Water Service Co.	A+/Negative/--	Excellent	Intermediate	Strong
California Independent System Operator Corp.	A/Stable/--	Excellent	Intermediate	Adequate
San Diego Gas & Electric Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Southern California Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
Alabama Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Georgia Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Mississippi Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Gulf Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
San Jose Water Co.	A/Stable/--	Excellent	Intermediate	Adequate
New Jersey Natural Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Laclede Gas Co.	A/Stable/A-1	Excellent	Intermediate	Strong
The Laclede Group Inc.	A/Stable/--	Excellent	Intermediate	Strong
The Brooklyn Union Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
KeySpan Gas East Corp.	A/Stable/--	Excellent	Intermediate	Adequate

U.S. Regulated Utilities (cont.)				
Southern Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Corp.	A/Stable/A-1	Excellent	Intermediate	Adequate
Connecticut Water Service Inc.	A/Negative/--	Excellent	Significant	Adequate
The Connecticut Water Co.	A/Negative/--	Excellent	Significant	Adequate
Central Hudson Gas & Electric Corp.	A/Watch Neg/--	Excellent	Significant	Strong
NSTAR Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Yankee Gas Services Co.	A-/Stable/--	Excellent	Significant	Adequate
NSTAR Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Western Massachusetts Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Connecticut Light & Power Co.	A-/Stable/--	Excellent	Significant	Adequate
Public Service Co. of New Hampshire	A-/Stable/--	Excellent	Significant	Adequate
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Gas LLC	A-/Stable/A-2	Excellent	Significant	Adequate
The York Water Co.	A-/Stable/--	Excellent	Significant	Adequate
Middlesex Water Co.	A-/Stable/--	Excellent	Significant	Adequate
United Water New Jersey Inc.	A-/Stable/--	Excellent	Significant	Adequate
United Waterworks Inc.	A-/Stable/--	Excellent	Significant	Adequate
Indiana Gas Co. Inc.	A-/Stable/--	Excellent	Significant	Adequate
Boston Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Colonial Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Vectren Utility Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Carolinas LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Florida Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate	Adequate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Narragansett Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
New England Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Indiana Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Wisconsin	A-/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of Colorado	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Southwestern Public Service Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Power & Light Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Electric Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
The Peoples Gas Light & Coke Co.	A-/Stable/A-2	Excellent	Significant	Adequate
North Shore Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Peoples Energy Corp.	A-/Stable/--	Excellent	Significant	Adequate
Wisconsin Public Service Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Co.	A-/Stable/A-2	Excellent	Significant	Adequate
PacifiCorp	A-/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Duke Energy Kentucky Inc.	A-/Stable/--	Excellent	Significant	Adequate
Northeast Utilities	A-/Stable/--	Excellent	Significant	Adequate
NSTAR LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid USA	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
KeySpan Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Energy Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Xcel Energy Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Integrys Energy Group Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Vectren Corp.	A-/Stable/--	Excellent	Significant	Adequate
Duke Energy Ohio Inc.	A-/Stable/A-2	Strong	Significant	Adequate
NextEra Energy Inc.	A-/Stable/--	Strong	Intermediate	Adequate
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate
Progress Energy Inc.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate
Atlanta Gas Light Co.	BBB+/Stable/--	Excellent	Significant	Adequate
Nicor Gas Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Atmos Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Tampa Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
International Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Midwest LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Michigan Electric Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Great Plains LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania-American Water Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
New Jersey-American Water Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
American Water Works Co. Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
American Water Capital Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
CenterPoint Energy Houston Electric LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Cascade Natural Gas Corp.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Montana-Dakota Utilities Co.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Southwest Gas Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
Interstate Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of North Carolina Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
South Carolina Electric & Gas Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Oncor Electric Delivery Co. LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Significant	Strong
Potomac Electric Power Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Delmarva Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Atlantic City Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Central Maine Power Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
New York State Electric & Gas Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
ITC Holdings Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
AGL Resources Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Holdings Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
TECO Energy Inc.	BBB+/Stable/--	Excellent	Significant	Adequate
SCANA Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Alliant Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
CenterPoint Energy Resources Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
CenterPoint Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
PEPCO Holdings Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
South Jersey Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Michigan Consolidated Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Detroit Edison Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Sempra Energy	BBB+/Stable/A-2	Strong	Intermediate	Adequate
DTE Energy Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
South Jersey Industries Inc.	BBB+/Stable/--	Strong	Significant	Adequate
OGE Energy Corp.	BBB+/Stable/A-2	Strong	Significant	Adequate
ALLETE Inc.	BBB+/Stable/A-2	Strong	Significant	Adequate
Public Service Electric & Gas Co.	BBB/Positive/A-2	Excellent	Significant	Adequate
Arizona Public Service Co.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
Pinnacle West Capital Corp.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
Rochester Gas & Electric Corp.	BBB/Positive/--	Excellent	Aggressive	Adequate
PECO Energy Co.	BBB/Stable/A-2	Excellent	Significant	Adequate
Commonwealth Edison Co.	BBB/Stable/A-2	Excellent	Significant	Adequate
PPL Electric Utilities Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
AEP Texas Central Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
AEP Texas North Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Westar Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Kansas Gas & Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Connecticut Natural Gas Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Southern Connecticut Gas Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
The United Illuminating Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Utilities Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Louisville Gas & Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
LG&E and KU Energy LLC	BBB/Stable/--	Excellent	Aggressive	Adequate
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
NorthWestern Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive	Adequate

U.S. Regulated Utilities (cont.)				
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kansas City Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
KCP&L Greater Missouri Operations Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Great Plains Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Cleco Power LLC	BBB/Stable/--	Excellent	Aggressive	Strong
Avista Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Portland General Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Puget Sound Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive	Strong
El Paso Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
PPL Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
UIL Holdings Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Cleco Corp.	BBB/Stable/--	Excellent	Aggressive	Strong
IDACORP Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Pacific Gas & Electric Co.	BBB/Stable/A-2	Strong	Significant	Adequate
PG&E Corp.	BBB/Stable/--	Strong	Significant	Adequate
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive	Adequate
Entergy Gulf States Louisiana LLC	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Louisiana LLC	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Mississippi Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Arkansas Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Texas Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy New Orleans Inc.	BBB/Negative/--	Excellent	Significant	Adequate
System Energy Resources Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Corp.	BBB/Negative/--	Strong	Significant	Adequate
SEMCO Energy Inc.	BBB-/Watch Pos/--	Excellent	Significant	Adequate
Trans-Allegheny Interstate Line Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNG Cos. LLC	BBB-/Stable/--	Excellent	Aggressive	Adequate
Bay State Gas Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ameren Illinois Co.	BBB-/Stable/A-3	Excellent	Significant	Adequate
Ameren Missouri	BBB-/Stable/A-3	Excellent	Significant	Adequate
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Electric Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Metropolitan Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Jersey Central Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ohio Edison Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Cleveland Electric Illuminating Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Toledo Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Duquesne Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate

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

*Ratings as of April 20, 2012.

McGRAW-HILL

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue E2
Schedule 21.4
Attachment B

STANDARD
&POOR'S

Global Credit Portal®
RatingsDirect®

December 2, 2010

Issuer Ranking:

Issuer Ranking: Canadian Gas And Electric Utility Companies, Strongest To Weakest

Primary Credit Analysts:
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Issuer Ranking: Canadian Gas And Electric Utility Companies, Strongest To Weakest

The following list ranks Standard & Poor's Ratings Services' ratings, outlooks, and overall credit strength for Canadian electric utilities and generators, gas distribution utilities and pipelines, and utilities with provincial debt guarantees. The lists reflect ratings and outlooks as of Dec. 2, 2010. The rankings within each rating/outlook grouping (e.g., A/Stable/--) are based on relative overall credit quality. For the most recent report card, please see "Industry Report Card: Canadian Utilities' Credit Quality Stays Stable Overall; 2012 Refinancing Will Be High But Manageable," published July 22, 2010, on RatingsDirect on the Global Credit Portal.

Business risk and financial risk profiles in the utility sector are described using Standard & Poor's 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 our 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 And Financial Risk Profile Matrix

	--Financial Risk Profile--					
Business 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. The matrix does not apply to project finance.

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

Table 2

Financial Risk Indicative Ratios For Corporate Issuers (cont.)			
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
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

A Standard & Poor's outlook assesses the potential direction of the long-term rating on the issuer in the medium-to-long term. 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, on RatingsDirect on the Global Credit Portal). An outlook is not necessarily a precursor of a rating change or CreditWatch action. "Positive" indicates that we believe there is a trend with 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.

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.

Table 3

Issuer Ranking: Canadian Gas And Electric Utility Sector*

Electric utilities and generation

Issuers	Corporate credit rating	Business risk	Financial risk	Analyst
Hydro One Inc.	A+/Stable/A-1	Excellent	Intermediate	Greg Pau
Canadian Utilities Ltd.	A/Stable/A-1	Excellent	Intermediate	Gavin Macfarlane
ATCO Ltd.	A/Stable/--	Excellent	Intermediate	Gavin Macfarlane
CU Inc.	A/Stable/A-1	Excellent	Intermediate	Gavin Macfarlane
Hydro Ottawa Holding Inc.	A/Stable/--	Excellent	Intermediate	Greg Pau
Toronto Hydro Corp.	A/Stable/--	Excellent	Intermediate	Greg Pau
London Hydro Inc.	A/Stable/--	Excellent	Intermediate	Greg Pau
Borealis Infrastructure Trust (Enersource Bonds)¶	A	Excellent	Intermediate	Greg Pau
Guelph Hydro Electric Systems Inc.	A/Stable/--	Excellent	Intermediate	Greg Pau
Horizon Holdings Inc.	A/Stable/--	Excellent	Intermediate	Greg Pau
Hamilton Utilities Corp.	A/Stable/--	Excellent	Intermediate	Greg Pau
Chatham Kent Energy Inc.	A/Stable/--	Excellent	Intermediate	Greg Pau
Electricity Distributors Finance Corp.¶	A	Excellent	Intermediate	Greg Pau
Caribbean Utilities Co. Ltd.	A/Negative/--	Excellent	Significant	Nicole Martin
AltaLink L.P.	A-/Stable/--	Excellent	Significant	Nicole Martin
FortisAlberta Inc.	A-Stable/--	Excellent	Significant	Nicole Martin
Fortis Inc.	A-/Stable/--	Excellent	Significant	Nicole Martin
Ontario Power Generation Inc.§	A-/Stable/--	Strong	Significant	Greg Pau
EPCOR Utilities Inc.	BBB+/Stable/--	Strong	Intermediate	Greg Pau

Table 3

Issuer Ranking: Canadian Gas And Electric Utility Sector* (cont.)				
Nova Scotia Power Inc.	BBB+/Stable/--	Strong	Intermediate	Bato Kacarevic
Emera Inc.	BBB+/Stable/--	Strong	Intermediate	Bato Kacarevic
Maritime Electric Co. Ltd.	BBB+/Stable/--	Strong	Intermediate	Nicole Martin
ENMAX Corp.	BBB+/Stable/--	Strong	Significant	Greg Pau
TransAlta Corp.	BBB/Stable/--	Satisfactory	Intermediate	Gavin Macfarlane
Brookfield Renewable Power Inc.	BBB/Stable/A-3	Satisfactory	Intermediate	Greg Pau
Brookfield Renewable Power Fund	BBB/Stable/--	Strong	Significant	Greg Pau
Capital Power Income L.P.	BBB/Stable	Satisfactory	Intermediate	Greg Pau
Capital Power L.P.	BBB/Stable/--	Satisfactory	Intermediate	Greg Pau
Capital Power Corp.	BBB/Stable/--	Satisfactory	Intermediate	Greg Pau
AltaLink Investments L.P.	BBB-/Stable/--	Excellent	Aggressive	Nicole Martin
Innergex Renewable Energy Inc.	BBB-/Stable/--	Strong	Significant	Bato Kacarevic
Algonquin Power Co.	BBB-/Stable/--	Satisfactory	Intermediate	Bato Kacarevic
Northland Power Income Fund	BBB-/Stable/--	Satisfactory	Significant	Bato Kacarevic
Gas distribution utilities and pipelines				
Inter Pipeline (Corridor) Inc.	A-/Positive/--	Strong	Intermediate	Bato Kacarevic
Enbridge Gas Distribution Inc.	A-/Stable/--	Excellent	Significant	Gavin Macfarlane
Enbridge Pipelines Inc.	A-/Stable/--	Excellent	Significant	Gavin Macfarlane
Enbridge Inc.	A-/Stable/--	Excellent	Significant	Gavin Macfarlane
TransCanada Corp. and TransCanada PipeLines Ltd.	A-/Stable/--	Excellent	Significant	Nicole Martin
Gaz Metro Inc. and Gaz Metro L.P.	A-/Stable/--	Excellent	Significant	Bato Kacarevic
Union Gas Ltd.**	BBB+/Stable/A-2	Strong	Intermediate	Bato Kacarevic
Westcoast Energy Inc.**	BBB+/Stable/--	Strong	Intermediate	Bato Kacarevic
Trans Quebec & Maritimes Pipeline Inc.	BBB+/Stable/--	Strong	Significant	Bato Kacarevic
Pembina Pipeline Corp.	BBB+/Stable/--	Strong	Significant	Bato Kacarevic
Inter Pipeline Fund	BBB/Positive/--	Satisfactory	Intermediate	Bato Kacarevic
Fort Chicago Energy Partners L.P.	BBB/Stable/--	Strong	Significant	Bato Kacarevic
AltaGas Ltd.	BBB/Stable/--	Strong	Significant	Bato Kacarevic
Gibson Energy ULC	B+/Stable/--	Fair	Aggressive	Bato Kacarevic

*Ratings as of Dec. 2, 2010. ¶Debt rating. §Business and financial risk profiles reflect OPG's standalone credit risk profile as per our government-related entity criteria.
**Reflects the rating on owner Spectra Energy Corp. (BBB+/Stable/--).

CONTRACT DEMAND ENERGY (CDE) REPORT - Mainline

As Of Date: 2011-Jan-04

Service Type: FST, FT, FT-NR, FT-SN, LTWFS, STS

Contract Number	Service Requester	Contract Start Date	Contract End Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)	Operational Demand (GJ/d)	Shifted Qty (GJ/d)	Temp Assigned Qty (GJ/d)
5107	Bunge Canada	1994-Nov-01	2011-Oct-31	FT	Welwyn	Centram MDA	1,407	1,407	0	0
37575	Centra Gas Manitoba Inc.	2009-Nov-01	2011-Oct-31	FT	Empress	Centram MDA	135,000	135,000	0	0
29802	Diageo Canada Inc.	2006-May-15	2011-Oct-31	FT	Empress	Centram MDA	400	0	0	400
29803	Diageo Canada Inc.	2006-May-15	2011-Oct-31	FT	Empress	Centram MDA	2,400	0	0	2,400
41189	Gerdau Ameristeel Corporation	2011-Jan-01	2012-Mar-31	FT	Empress	Centram MDA	1,000	1,000	0	0
41024	Husky Energy Marketing Inc.	2010-Nov-01	2011-Oct-31	FT	Empress	Centram MDA	5,000	5,000	0	0
40373	Koch Canada Energy Services, LP	2010-Nov-01	2011-Oct-31	FT	Welwyn	Centram MDA	15,422	15,422	0	0
40374	Koch Canada Energy Services, LP	2010-Nov-01	2011-Oct-31	FT	Empress	Centram MDA	32,917	32,917	0	0
5665	Maple Leaf Foods Inc.	1995-Nov-01	2011-Oct-31	FT	Empress	Centram MDA	706	0	0	706
26474	McCain Foods Limited	2005-Mar-01	2011-Oct-31	FT	Empress	Centram MDA	1,200	0	0	1,200
35633	McCain Foods Limited	2008-Nov-01	2011-Oct-31	FT	Empress	Centram MDA	1,700	1,700	0	0
						Centram MDA Total	**197,152**	**192,446**	**0**	**4,706**
3036	Centra Gas Manitoba Inc.	1993-Dec-01	2011-Oct-31	FT	Empress	Centram SSDA	2,200	2,200	0	0
40121	TransGas Limited	2010-Nov-01	2011-Oct-31	FT	Empress	Centram SSDA	1,500	1,500	0	0
41086	TransGas Limited	2010-Nov-01	2011-Oct-31	FT	Empress	Centram SSDA	7	7	0	0
						Centram SSDA Total	**3,707**	**3,707**	**0**	**0**
29357	Abitibi-Consolidated Company of Canada	2006-Mar-01	2011-Oct-31	FT	Empress	Centrat MDA	2,500	2,500	0	0
1929	Centra Transmission Holdings Inc.	1990-Dec-09	2011-Oct-31	FT	Empress	Centrat MDA	1,130	1,130	0	0
6309	Union Gas Limited	1996-Jul-01	2011-Dec-31	FT	Empress	Centrat MDA	4,522	4,522	0	0
						Centrat MDA Total	**8,152**	**8,152**	**0**	**0**
36758	Dynegy Gas Imports, LLC	2008-Dec-01	2015-Oct-31	FT	Kirkwall	Chippawa	41,491	41,491	0	0
36759	Dynegy Gas Imports, LLC	2008-Dec-01	2015-Oct-31	FT	St. Clair	Chippawa	124,142	124,142	0	0
30025	Infinite Energy, Inc.	2006-Nov-01	2011-Mar-31	FT	Empress	Chippawa	300	300	0	0
33197	Infinite Energy, Inc.	2007-Nov-01	2011-Mar-31	FT	Empress	Chippawa	500	500	0	0
40088	J. Aron & Company	2010-Aug-01	2011-Mar-31	FT	St. Clair	Chippawa	29,183	29,183	0	0
40091	J. Aron & Company	2010-Aug-01	2011-Mar-31	FT	Union Dawn	Chippawa	40,000	40,000	0	0
35799	KeySpan Gas East Corporation	2008-Nov-01	2018-Oct-31	FT	Kirkwall	Chippawa	137,157	0	0	137,157
41226	National Fuel Gas Distribution Corporation	2006-Nov-01	2017-Oct-31	FT	Kirkwall	Chippawa	10,699	4,896	0	5,803
41227	National Fuel Gas Distribution Corporation	2007-Nov-01	2020-Oct-31	FT	Kirkwall	Chippawa	15,794	5,083	0	10,711
5020	New York State Electric & Gas Corporation	1994-Nov-01	2011-Oct-31	FT	Empress	Chippawa	10,593	0	0	10,593
2937	Rochester Gas and Electric Corporation	1993-Nov-01	2011-Oct-31	FT	St. Clair	Chippawa	37,262	0	0	37,262
2939	Rochester Gas and Electric Corporation	1993-Nov-01	2011-Oct-31	FT	St. Clair	Chippawa	107,541	0	0	107,541
33199	Shell Energy North America (Canada) Inc.	2007-Nov-01	2012-Oct-31	FT	Kirkwall	Chippawa	8,706	8,706	0	0
35663	Shell Energy North America (Canada) Inc.	2008-Nov-01	2011-Oct-31	FT	Kirkwall	Chippawa	1,317	1,317	0	0
						Chippawa Total	**564,685**	**255,618**	**0**	**309,067**
13611	Alcoa Inc.	1999-Dec-01	2011-Oct-31	FT	Empress	Cornwall	1,294	1,294	0	0
32436	Alcoa Inc.	2007-Nov-01	2013-Jun-30	FT	Empress	Cornwall	6,000	6,000	0	0
18342	Canton Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	63	0	0	63
27539	Canton Central School District	2005-Nov-01	2011-Oct-31	FT	Empress	Cornwall	3	0	0	3
13292	City of Ogdensburg	1999-Nov-01	2011-Oct-31	FT	Empress	Cornwall	19	0	0	19
18321	Clarkson University	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	525	0	0	525
18320	Heuvelton Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	34	0	0	34
18349	Hoosier Magnetics, Inc.	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	374	0	0	374
27540	Hoosier Magnetics, Inc.	2005-Nov-01	2011-Oct-31	FT	Empress	Cornwall	26	0	0	26

CONTRACT DEMAND ENERGY (CDE) REPORT - Mainline

TransCanada
In business to deliver

As Of Date: 2011-Jan-04

Service Type: FST, FT, FT-NR, FT-SN, LTWFS, STS

Contract Number	Service Requester	Contract Start Date	Contract End Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)	Operational Demand (GJ/d)	Shifted Qty (GJ/d)	Temp Assigned Qty (GJ/d)
18338	Lisbon Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	19	0	0	19
27537	Lisbon Central School District	2005-Nov-01	2011-Oct-31	FT	Empress	Cornwall	2	0	0	2
18328	Madrid-Waddington Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	26	0	0	26
18318	Massena Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	135	0	0	135
27538	Massena Central School District	2005-Nov-01	2011-Oct-31	FT	Empress	Cornwall	4	0	0	4
18341	Norwood-Norfolk Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	49	0	0	49
31593	Ogdensburg City School District	2006-Nov-01	2011-Oct-31	FT	Empress	Cornwall	19	0	0	19
31594	Ogdensburg City School District	2006-Nov-01	2011-Oct-31	FT	Empress	Cornwall	75	0	0	75
18340	Potsdam Central School District	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	83	0	0	83
19233	St. Lawrence Gas Company, Inc.	2002-Nov-01	2011-Oct-31	STS	Union Parkway Belt	Cornwall	10,300	10,300	0	0
19331	St. Lawrence Gas Company, Inc.	2003-Nov-01	2011-Oct-31	FT	Empress	Cornwall	7,100	7,100	0	0
21988	St. Lawrence Gas Company, Inc.	2003-Nov-01	2011-Oct-31	FT	Empress	Cornwall	3,200	3,200	0	0
13375	St. Lawrence University	1999-Nov-01	2011-Oct-31	FT	Empress	Cornwall	362	0	0	362
33328	St. Lawrence University	2007-Nov-01	2011-Oct-31	FT	Empress	Cornwall	54	0	0	54
18317	St. Regis Nursing Home and Health Related Facility, Inc.	2002-Nov-01	2011-Oct-31	FT	Empress	Cornwall	29	0	0	29
						Cornwall Total	**29,795**	**27,894**	**0**	**1,901**
33321	Bay State Gas Company	2007-Nov-01	2018-Mar-31	FT	Union Dawn	East Hereford	16,881	0	0	16,881
12217	DTE Energy Trading, Inc.	1999-Mar-10	2011-Mar-31	FT	St. Clair	East Hereford	16,646	16,646	0	0
33322	Northern Utilities, Inc.	2007-Nov-01	2018-Mar-31	FT	Union Dawn	East Hereford	35,872	0	0	35,872
						East Hereford Total	**69,399**	**16,646**	**0**	**52,753**
2771	Centra Gas Manitoba Inc.	1993-Apr-01	2012-Mar-31	STS	Centram MDA	Emerson 2	54,000	54,000	0	0
12359	City of Duluth	1999-Nov-01	2014-Oct-31	FT	Empress	Emerson 2	6,532	0	0	6,532
10587	United States Gypsum Company	1997-Nov-01	2012-Oct-31	FT	Empress	Emerson 2	14,550	0	0	14,550
						Emerson 2 Total	**75,082**	**54,000**	**0**	**21,082**
20394	Ag Energy Co-operative Ltd.	2003-Nov-01	2011-Oct-31	FT	Union Dawn	Enbridge CDA	4,700	4,700	0	0
20395	Canada Starch Operating Company Inc.	2003-Nov-01	2011-Dec-31	FT	Union Dawn	Enbridge CDA	4,398	4,398	0	0
1349	Enbridge Gas Distribution Inc.	1989-Nov-01	2011-Oct-31	FT	Empress	Enbridge CDA	40,093	32,327	0	7,766
2623	Enbridge Gas Distribution Inc.	1992-Nov-01	2011-Oct-31	STS	Union Parkway Belt	Enbridge CDA	153,700	153,700	0	0
15957	Enbridge Gas Distribution Inc.	2001-Nov-01	2011-Oct-31	STS	Union Parkway Belt	Enbridge CDA	92,822	92,822	0	0
18786	Enbridge Gas Distribution Inc.	2002-Nov-01	2011-Oct-31	STS	Union Parkway Belt	Enbridge CDA	37,370	37,370	0	0
20260	Enbridge Gas Distribution Inc.	2003-Nov-01	2011-Oct-31	FT	Union Dawn	Enbridge CDA	4,818	4,818	0	0
20266	Enbridge Gas Distribution Inc.	2003-Nov-01	2011-Oct-31	FT	Union Dawn	Enbridge CDA	145,000	95,898	0	49,102
29244	Enbridge Gas Distribution Inc.	2006-Apr-01	2011-Oct-31	FT	Empress	Enbridge CDA	15,000	15,000	0	0
35516	Enbridge Gas Distribution Inc.	2008-Nov-01	2013-Oct-31	FT	Union Parkway Belt	Enbridge CDA	572	572	0	0
38826	Enbridge Gas Distribution Inc.	2009-Nov-01	2011-Oct-31	FT	Empress	Enbridge CDA	8,375	8,375	0	0
20383	Greater Toronto Airports Authority	2003-Nov-01	2011-Oct-31	FT	Union Dawn	Enbridge CDA	1,100	1,100	0	0
28756	Greater Toronto Airports Authority	2006-Apr-01	2018-Oct-31	FT	Union Parkway Belt	Enbridge CDA	7,500	3,800	0	3,700
20224	Oxy Vinyls Canada Co.	2003-Apr-01	2011-Oct-31	FT	Union Dawn	Enbridge CDA	1,800	1,800	0	0
38224	Shell Energy North America (Canada) Inc.	2009-Oct-01	2011-Oct-31	FT	Union Dawn	Enbridge CDA	2,600	2,600	0	0
6643	Whitby Cogeneration Limited Partnership	1996-Nov-01	2011-Dec-31	FT	Empress	Enbridge CDA	11,382	0	0	11,382
						Enbridge CDA Total	**531,230**	**459,280**	**0**	**71,950**
32625	Carleton University	2007-Nov-01	2012-Oct-31	FT	Empress	Enbridge EDA	451	451	0	0
1140	Enbridge Gas Distribution Inc.	1989-Aug-08	2011-Oct-31	STS	Union Parkway Belt	Enbridge EDA	35,089	35,089	0	0
1338	Enbridge Gas Distribution Inc.	1989-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	32,357	26,176	0	6,181
2172	Enbridge Gas Distribution Inc.	1991-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	21,584	11,399	0	10,185
5019	Enbridge Gas Distribution Inc.	1994-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	7,613	7,613	0	0
5445	Enbridge Gas Distribution Inc.	1995-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	19,692	19,692	0	0

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5834	Enbridge Gas Distribution Inc.	1995-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	10,773	10,773	0	0
6646	Enbridge Gas Distribution Inc.	1996-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	10,773	10,773	0	0
10862	Enbridge Gas Distribution Inc.	1997-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	26,952	26,952	0	0
13307	Enbridge Gas Distribution Inc.	1999-Nov-01	2011-Oct-31	STS	Union Parkway Belt	Enbridge EDA	35,806	35,806	0	0
21854	Enbridge Gas Distribution Inc.	2003-Nov-01	2011-Oct-31	STS	Union Parkway Belt	Enbridge EDA	9,716	9,716	0	0
21987	Enbridge Gas Distribution Inc.	2003-Nov-01	2011-Oct-31	FT	Union Dawn	Enbridge EDA	114,000	114,000	0	0
34937	Enbridge Gas Distribution Inc.	2008-Nov-01	2013-Oct-31	FT	Empress	Enbridge EDA	25,000	25,000	0	0
36057	Enbridge Gas Distribution Inc.	2009-Nov-01	2011-Oct-31	FT	Empress	Enbridge EDA	42,226	42,226	0	0
						Enbridge EDA Total	**392,032**	**375,666**	**0**	**16,366**
39499	BP Canada Energy Company	2010-Mar-01	2011-Oct-31	FT	Iroquois	GMIT EDA	8,267	8,267	0	0
39500	BP Canada Energy Company	2010-Apr-01	2011-Oct-31	FT	Iroquois	GMIT EDA	18,685	18,685	0	0
39571	Direct Energy Marketing Limited	2010-Nov-01	2012-Oct-31	FT	Iroquois	GMIT EDA	25,000	25,000	0	0
20562	Domtar Inc.	2003-May-01	2011-Oct-31	FT	Empress	GMIT EDA	2,500	2,500	0	0
1141	Gaz Metro Limited Partnership	1985-Nov-01	2012-Apr-15	STS	Union Parkway Belt	GMIT EDA	25,629	25,629	0	0
1741	Gaz Metro Limited Partnership	1990-Oct-01	2011-Oct-31	FT	Empress	GMIT EDA	232,451	145,451	0	87,000
6245	Gaz Metro Limited Partnership	1996-Apr-16	2012-Apr-15	STS	Union Parkway Belt	GMIT EDA	125,545	125,545	0	0
11209	Gaz Metro Limited Partnership	1998-Dec-10	2011-Dec-09	FT	Empress	GMIT EDA	44,523	44,523	0	0
16106	Gaz Metro Limited Partnership	2001-Nov-01	2011-Oct-31	STS	Union Parkway Belt	GMIT EDA	45,000	45,000	0	0
20268	Gaz Metro Limited Partnership	2003-Nov-01	2011-Oct-31	FT	Union Dawn	GMIT EDA	50,000	50,000	0	0
21989	Gaz Metro Limited Partnership	2005-Nov-01	2015-Oct-31	FT	Union Dawn	GMIT EDA	40,000	40,000	0	0
22306	Gaz Metro Limited Partnership	2005-Nov-01	2015-Oct-31	STS	Union Parkway Belt	GMIT EDA	20,000	20,000	0	0
22521	Gaz Metro Limited Partnership	2003-Nov-01	2011-Oct-31	FT	Union Dawn	GMIT EDA	20,000	20,000	0	0
33680	Gaz Metro Limited Partnership	2007-Nov-01	2017-Oct-31	FT	Union Parkway Belt	GMIT EDA	65,000	65,000	0	0
37573	J.P. Morgan Commodities Canada Corporation	2009-Nov-01	2011-Oct-31	FT	Iroquois	GMIT EDA	10,000	10,000	0	0
39572	J.P. Morgan Commodities Canada Corporation	2010-Nov-01	2011-Oct-31	FT	Iroquois	GMIT EDA	3,048	3,048	0	0
35449	Kruger Inc.	2008-Jul-01	2011-Oct-31	FT	Empress	GMIT EDA	771	771	0	0
36866	Shell Energy North America (Canada) Inc.	2009-Apr-01	2012-Mar-31	FT	Iroquois	GMIT EDA	10,000	10,000	0	0
36886	Shell Energy North America (Canada) Inc.	2009-Apr-01	2012-Mar-31	FT	Iroquois	GMIT EDA	10,000	10,000	0	0
29557	TransCanada Energy Ltd.	2006-Dec-02	2018-Dec-31	FT	Union Dawn	GMIT EDA	100,000	23,300	0	76,700
						GMIT EDA Total	**856,419**	**692,719**	**0**	**163,700**
1085	Gaz Metro Limited Partnership	1988-Nov-01	2011-Oct-31	FT	Empress	GMIT NDA	12,397	12,397	0	0
21659	Gaz Metro Limited Partnership	2003-Nov-01	2011-Oct-31	FT	Empress	GMIT NDA	2,930	2,930	0	0
						GMIT NDA Total	**15,327**	**15,327**	**0**	**0**
36992	Goreway Station Partnership	2009-Jan-01	2028-Oct-31	FT-SN	Union Parkway Belt	Goreway CDA	20,000	20,000	0	0
36993	Goreway Station Partnership	2009-Jan-01	2011-Oct-31	FT-SN	Union Parkway Belt	Goreway CDA	120,000	120,000	0	0
						Goreway CDA Total	**140,000**	**140,000**	**0**	**0**
41234	Bay State Gas Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	27,498	0	0	27,498
41218	Boston Gas Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	2,134	0	0	2,134
41229	Boston Gas Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	9,180	0	0	9,180
5507	Brooklyn Navy Yard Cogeneration Partners, L.P.	1996-Oct-01	2016-Oct-31	FT	Empress	Iroquois	26,956	0	0	26,956
41233	Central Hudson Gas & Electric Corporation	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	10,674	10,674	0	0
41219	Colonial Gas Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	6,404	0	0	6,404
41224	Connecticut Natural Gas Corporation	2007-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	264	264	0	0
41225	Connecticut Natural Gas Corporation	2008-Nov-01	2019-Oct-31	FT	Union Parkway Belt	Iroquois	6,436	6,436	0	0
41238	Connecticut Natural Gas Corporation	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	17,879	17,879	0	0
41239	Connecticut Natural Gas Corporation	2007-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Iroquois	8,807	8,807	0	0
40085	Enbridge Gas Distribution Inc.	2010-Sep-01	2012-Mar-31	FT	Union Dawn	Iroquois	40,000	40,000	0	0
41232	EnergyNorth Natural Gas, Inc.	2007-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	4,270	0	0	4,270
21962	Husky Energy Marketing Inc.	2003-Oct-01	2012-Oct-31	FT	Empress	Iroquois	13,557	13,557	0	0

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40090	J. Aron & Company	2010-Aug-01	2011-Apr-30	FT	Union Dawn	Iroquois	1,000	1,000	0	0
27212	J.P. Morgan Commodities Canada Corporation	2005-Jul-21	2013-Oct-31	FT	Empress	Iroquois	15,103	15,103	0	0
41220	KeySpan Gas East Corporation	2007-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Iroquois	22,522	0	0	22,522
41228	KeySpan Gas East Corporation	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	16,972	0	0	16,972
34834	New York State Electric & Gas Corporation	2008-Feb-01	2011-Oct-31	FT	Empress	Iroquois	7,205	0	0	7,205
36182	Niagara Mohawk Power Corporation	2008-Nov-01	2012-Apr-30	FT	Empress	Iroquois	26,952	0	0	26,952
41235	Northern Utilities, Inc.	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	6,264	0	0	6,264
11789	Paramount Resources Ltd.	1998-Nov-01	2012-Oct-31	FT	Empress	Iroquois	6,406	0	0	6,406
14109	Paramount Resources Ltd.	2000-May-01	2014-Oct-31	FT	Empress	Iroquois	811	0	0	811
5048	Selkirk Cogen Partners, L.P.	1994-Nov-01	2014-Oct-31	FT	Empress	Iroquois	58,485	58,485	0	0
27213	Shell Energy North America (Canada) Inc.	2005-Nov-01	2012-Oct-31	FT	Empress	Iroquois	16,234	16,234	0	0
35059	Tenaska Marketing Canada, a division of TMV Corp.	2008-Mar-01	2011-Mar-31	FT	Empress	Iroquois	27,484	27,484	0	0
41215	The Brooklyn Union Gas Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	12,810	0	0	12,810
41217	The Brooklyn Union Gas Company	2007-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Iroquois	29,886	0	0	29,886
41221	The Southern Connecticut Gas Company	2007-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	475	475	0	0
41222	The Southern Connecticut Gas Company	2008-Nov-01	2019-Oct-31	FT	Union Parkway Belt	Iroquois	9,656	9,656	0	0
41230	The Southern Connecticut Gas Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	34,567	34,567	0	0
41231	The Southern Connecticut Gas Company	2007-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Iroquois	13,342	13,342	0	0
41223	Yankee Gas Services Company	2008-Nov-01	2019-Oct-31	FT	Union Parkway Belt	Iroquois	5,336	0	0	5,336
41236	Yankee Gas Services Company	2006-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Iroquois	42,642	0	0	42,642
41237	Yankee Gas Services Company	2007-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Iroquois	20,334	0	0	20,334
						Iroquois Total	**548,545**	**273,963**	**0**	**274,582**
1066	1425445 Ontario Limited	1989-Jan-01	2011-Dec-31	FT	Empress	KPUC EDA	7,786	7,786	0	0
1138	1425445 Ontario Limited	1975-Apr-01	2011-Oct-31	STS	Union Parkway Belt	KPUC EDA	13,167	13,167	0	0
						KPUC EDA Total	**20,953**	**20,953**	**0**	**0**
2980	New York State Electric & Gas Corporation	1993-Nov-01	2011-Oct-31	FT	Empress	Napierville	4,775	0	0	4,775
2981	New York State Electric & Gas Corporation	1993-Nov-01	2011-Oct-31	FT	Empress	Napierville	3,805	0	0	3,805
						Napierville Total	**8,580**	**0**	**0**	**8,580**
29459	3095381 Nova Scotia Company	2006-Apr-01	2012-Jul-01	FT	Empress	Niagara Falls	15,934	0	0	15,934
28960	Cargill Limited	2006-Jan-01	2011-Apr-30	FT	Empress	Niagara Falls	27,002	27,002	0	0
40086	J. Aron & Company	2010-Aug-01	2011-Mar-31	FT	Union Dawn	Niagara Falls	142,433	142,433	0	0
40087	J. Aron & Company	2010-Aug-01	2011-Oct-31	FT	Empress	Niagara Falls	15,396	15,396	0	0
26469	National Fuel Gas Distribution Corporation	2005-Apr-01	2011-Mar-31	FT	Union Dawn	Niagara Falls	28,854	0	0	28,854
36163	United States Gypsum Company	2008-Nov-01	2011-Oct-31	FT	Empress	Niagara Falls	11,606	0	3,000	8,606
35096	Yankee Gas Services Company	2008-Apr-01	2018-Mar-31	FT	Union Dawn	Niagara Falls	10,265	0	0	10,265
						Niagara Falls Total	**251,490**	**184,831**	**3,000**	**63,659**
35627	Rock-Tenn Shared Services, LLC	2008-Nov-01	2011-Oct-31	FT	Herbert	Philipsburg	2,005	0	0	2,005
33045	Vermont Gas Systems, Inc.	2007-Nov-01	2017-Oct-31	FT	Empress	Philipsburg	12,000	12,000	0	0
33556	Vermont Gas Systems, Inc.	2007-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Philipsburg	10,000	10,000	0	0
34490	Vermont Gas Systems, Inc.	2008-Apr-01	2011-Nov-30	FT	Empress	Philipsburg	6,500	6,500	0	0
34728	Vermont Gas Systems, Inc.	2008-Apr-01	2020-Mar-31	STS	Union Parkway Belt	Philipsburg	20,279	20,279	0	0
36188	Vermont Gas Systems, Inc.	2008-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Philipsburg	10,000	0	0	10,000
36190	Vermont Gas Systems, Inc.	2008-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Philipsburg	2,000	0	0	2,000
						Philipsburg Total	**62,784**	**48,779**	**0**	**14,005**
40288	J. Aron & Company	2010-Nov-01	2011-Oct-31	FT	Empress	Spruce	5,275	5,275	0	0
						Spruce Total	**5,275**	**5,275**	**0**	**0**

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5044	Capital Power Income L.P.	1994-Nov-01	2014-Oct-31	FT	Empress	TCPL NDA	7,536	7,536	0	0
						TCPL NDA Total	**7,536**	**7,536**	**0**	**0**
13753	Capital Power Income L.P.	2000-Feb-01	2011-Oct-31	FT	Empress	TCPL WDA	6,502	6,502	0	0
						TCPL WDA Total	**6,502**	**6,502**	**0**	**0**
38101	Thorold CoGen L.P.	2009-Sep-01	2019-Aug-31	FT-SN	Kirkwall	Thorold CDA	49,500	49,500	0	0
						Thorold CDA Total	**49,500**	**49,500**	**0**	**0**
40120	TransGas Limited	2010-Nov-01	2011-Oct-31	FT	Empress	Transgas SSDA	10,000	10,000	0	0
40126	TransGas Limited	2010-Jul-15	2011-Oct-31	FT	Empress	Transgas SSDA	10,000	10,000	0	0
						Transgas SSDA Total	**20,000**	**20,000**	**0**	**0**
20397	Canada Starch Operating Company Inc.	2003-Nov-01	2011-Dec-31	FT	Union Dawn	Union CDA	699	699	0	0
20270	Shell Energy North America (Canada) Inc.	2003-Nov-01	2012-Mar-31	FT	Union Dawn	Union CDA	79,129	79,129	0	0
19332	The Corporation of the City of Kitchener	2003-Sep-01	2013-Oct-31	FT	Union Dawn	Union CDA	8,000	8,000	0	0
32907	The Corporation of the City of Kitchener	2007-Nov-01	2012-Oct-31	FT	Empress	Union CDA	500	500	0	0
32908	The Corporation of the City of Kitchener	2007-Nov-01	2011-Oct-31	FT	Empress	Union CDA	500	500	0	0
32909	The Corporation of the City of Kitchener	2007-Nov-01	2011-Oct-31	FT	Empress	Union CDA	500	500	0	0
12458	Toyota Motor Manufacturing North America, Inc.	1999-Nov-01	2011-Oct-31	FT	Empress	Union CDA	948	948	0	0
1142	Union Gas Limited	1992-Apr-01	2011-Dec-31	STS	Union WDA	Union CDA	3,150	3,150	0	0
1142	Union Gas Limited	1992-Apr-01	2011-Dec-31	STS	Union NDA	Union CDA	49,100	49,100	0	0
2776	Union Gas Limited	1993-Apr-01	2012-Jan-31	FT	Empress	Union CDA	3,699	3,699	0	0
6673	Union Gas Limited	1996-Nov-01	2011-Dec-31	FT	Empress	Union CDA	1,979	1,979	0	0
12430	Union Gas Limited	1999-Nov-01	2011-Oct-31	FT	Empress	Union CDA	13,149	11,339	0	1,810
20259	Union Gas Limited	2003-Nov-01	2011-Oct-31	FT	Union Dawn	Union CDA	60,000	60,000	0	0
22754	Union Gas Limited	2003-Nov-01	2011-Oct-31	FT	Empress	Union CDA	40,000	0	0	40,000
39928	Union Gas Limited	2010-Nov-01	2015-Dec-31	FT	Empress	Union CDA	12,500	12,500	0	0
5039	West Windsor Power	1995-Sep-01	2015-Dec-31	FT	Empress	Union CDA	8,145	8,145	0	0
						Union CDA Total	**281,998**	**240,188**	**0**	**41,810**
20396	Canada Starch Operating Company Inc.	2003-Nov-01	2011-Dec-31	FT	Union Dawn	Union EDA	1,020	1,020	0	0
20398	Canada Starch Operating Company Inc.	2004-Jan-01	2011-Dec-31	FT	Union Dawn	Union EDA	490	490	0	0
29482	Dyno Nobel Nitrogen Inc.	2006-Mar-30	2011-Oct-31	FT	Empress	Union EDA	950	950	0	0
35657	GreenField Ethanol Inc.	2008-Nov-01	2018-Oct-31	FT	Union Parkway Belt	Union EDA	2,000	2,000	0	0
5106	Husky Energy Marketing Inc.	1994-Jul-01	2014-Oct-31	FT	Empress	Union EDA	33,563	33,563	0	0
6570	Kingston CoGen Limited Partnership	1996-Oct-01	2016-Oct-31	FT	Empress	Union EDA	21,045	21,045	0	0
12870	Ontario Power Generation Inc.	1999-Nov-01	2011-Oct-31	FT	Empress	Union EDA	4,000	4,000	0	0
1048	Union Gas Limited	1989-Jan-01	2011-Dec-31	FT	Empress	Union EDA	50,576	30,216	0	20,360
1142	Union Gas Limited	1992-Apr-01	2011-Dec-31	STS	Union Parkway Belt	Union EDA	68,520	68,520	0	0
2744	Union Gas Limited	1993-Nov-01	2011-Oct-31	FT	Empress	Union EDA	8,675	8,675	0	0
29591	Union Gas Limited	2006-Nov-01	2016-Oct-31	FT	Union Parkway Belt	Union EDA	30,000	30,000	0	0
33559	Union Gas Limited	2007-Nov-01	2017-Oct-31	FT	Union Parkway Belt	Union EDA	5,000	5,000	0	0
						Union EDA Total	**225,839**	**205,479**	**0**	**20,360**
1049	Union Gas Limited	1989-Jan-01	2011-Dec-31	FT	Empress	Union NCDA	9,211	7,251	0	1,960
1052	Union Gas Limited	1989-Apr-01	2011-Oct-31	FT	Empress	Union NCDA	1,545	1,545	0	0
						Union NCDA Total	**10,756**	**8,796**	**0**	**1,960**

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13757	Capital Power Income L.P.	2000-Feb-01	2016-Oct-31	FT	Empress	Union NDA	8,182	8,182	0	0
13758	Capital Power Income L.P.	2000-Feb-01	2016-Oct-31	FT	Empress	Union NDA	8,182	8,182	0	0
20375	Domtar Inc.	2003-Nov-01	2011-Oct-31	FT	Empress	Union NDA	1,000	1,000	0	0
6498	Iroquois Falls Power Corp.	1996-Sep-01	2016-Aug-31	FT	Empress	Union NDA	20,874	20,874	0	0
20547	Toromont Industries Ltd.	2003-May-01	2012-Apr-30	FT	Empress	Union NDA	374	374	0	0
1045	Union Gas Limited	1989-Jan-01	2011-Dec-31	FT	Empress	Union NDA	67,625	50,777	0	16,848
40444	Vale Canada Limited	2010-Nov-01	2011-Oct-31	FT	Empress	Union NDA	3,500	3,500	0	0
						Union NDA Total	**109,737**	**92,889**	**0**	**16,848**
39703	Lake Superior Power Limited Partnership	2011-Jan-01	2011-Dec-31	FT	SS. Marie	Union SSMDA	10,100	10,100	0	0
1047	Union Gas Limited	1989-Jan-01	2011-Dec-31	FT	Empress	Union SSMDA	9,143	8,143	0	1,000
						Union SSMDA Total	**19,243**	**18,243**	**0**	**1,000**
33195	BP Canada Energy Company	2007-Nov-01	2012-Mar-31	FT	St. Clair	Union SWDA	50,000	50,000	0	0
33327	Cargill Limited	2007-Nov-01	2011-Oct-31	FT	St. Clair	Union SWDA	5,275	5,275	0	0
37099	Cargill Limited	2009-Jan-22	2012-Jan-31	FT	St. Clair	Union SWDA	10,125	10,125	0	0
35447	Enserco Energy Inc.	2008-Nov-01	2011-Mar-31	FT	St. Clair	Union SWDA	26,343	26,343	0	0
37031	Enserco Energy Inc.	2009-Nov-01	2011-Mar-31	FT	St. Clair	Union SWDA	52,753	52,753	0	0
41507	Shell Energy North America (Canada) Inc.	2010-Dec-22	2012-Mar-31	FT	St. Clair	Union SWDA	63,874	63,874	0	0
37205	Suncor Energy Marketing Inc.	2009-Nov-01	2011-Mar-31	FT	St. Clair	Union SWDA	52,755	52,755	0	0
33194	Tenaska Marketing Canada, a division of TMV Corp.	2007-Nov-01	2011-Mar-31	FT	St. Clair	Union SWDA	20,000	20,000	0	0
33196	Tenaska Marketing Canada, a division of TMV Corp.	2007-Nov-01	2014-Mar-31	FT	St. Clair	Union SWDA	30,000	30,000	0	0
37212	Tenaska Marketing Canada, a division of TMV Corp.	2009-Apr-01	2011-Apr-30	FT	St. Clair	Union SWDA	13,859	13,859	0	0
37215	Tenaska Marketing Canada, a division of TMV Corp.	2009-Apr-01	2011-Mar-31	FT	St. Clair	Union SWDA	19,447	19,447	0	0
37241	Tenaska Marketing Canada, a division of TMV Corp.	2009-Apr-01	2011-Mar-31	FT	St. Clair	Union SWDA	22,200	22,200	0	0
40384	Union Gas Limited	2010-Nov-01	2011-Oct-31	FT	St. Clair	Union SWDA	10,551	10,551	0	0
34934	Virginia Power Energy Marketing, Inc.	2008-Feb-01	2011-Jan-31	FT	St. Clair	Union SWDA	20,000	20,000	0	0
						Union SWDA Total	**397,182**	**397,182**	**0**	**0**
1046	Union Gas Limited	1989-Jan-01	2011-Dec-31	FT	Empress	Union WDA	39,880	36,580	0	3,300
						Union WDA Total	**39,880**	**36,580**	**0**	**3,300**
37017	Enbridge Gas Distribution Inc.	2009-Jan-12	2018-Oct-31	FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	85,000	0	0
37098	Portlands Energy Centre L.P.	2009-Jan-22	2011-Nov-30	FT-SN	Union Parkway Belt	Victoria Square #2 CDA	100,000	100,000	0	0
						Victoria Square #2 CDA Total	**185,000**	**185,000**	**0**	**0**
40122	TransGas Limited	2010-Nov-01	2011-Oct-31	FT	Empress	Welwyn	6,000	6,000	0	0
40576	TransGas Limited	2010-Nov-01	2011-Oct-31	FT	Empress	Welwyn	10,943	10,943	0	0
						Welwyn Total	**16,943**	**16,943**	**0**	**0**
						Grand Total	**5,150,723**	**4,060,094**	**3,000**	**1,087,629**

CME, CCC, SEC, VECC INTERROGATORY #5

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

a) Please provide the CVs of the authors of the Concentric report.

RESPONSE

a) Please see the attachment.

Witnesses: J. Coyne
J. Lieberman
Concentric

James M. Coyne
Senior Vice President

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

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony and Litigation Experience

- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Terasen Utilities: provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District; provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)

- ATCO Utilities: primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board' policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values.
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2011)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

Financial and Economic Advisory Experience

- Advisor to a major international corporation in the strategic evaluation of the SmartGrid related business segments, and development of specific investment and acquisition options in those business segments. (2011)
- Advisor to the New Brunswick Department of Energy on facilitating cross-border exports of energy from the Canadian Maritimes to Northeast U.S. markets. (2008-2011)
- Financial advisor to a major international corporation for investments in U.S. nuclear generating units. (2007-2009)
- Lead regulatory and market due diligence advisor to Macquarie Securities in the $7.4 billion acquisition of Puget Sound Energy. (2007)

- Retained by five Vermont electric utilities to study the comparative economics building the next generation of electric power generation within the state. Working with the utilities, the Vermont Department of Public Service, and the Electric Power Research Institute (EPRI), ten possible generation technologies were analyzed for their economic and environmental attributes. Costs were compared across technologies, and financial impacts including credit rating were examined. The report was presented in public forums and before state agencies. (2007)
- Advisor to the City of Mesa, Arizona for the potential privatization of the City's electric utility. (2007-2008)
- Independent Market Expert for a large Midwestern utility seeking a credit rating for its electric generation subsidiary. Providing a complete PJM and MISO market assessment and forward financial projections for the company's generation business including over 13,000 MW's of generating capacity. Financial projections are based on LMP price projections for the PJM-MISO interconnect, fuels prices, air emissions prices, and complete financial analysis of the business unit. Also provided support for discussions with the major credit rating agencies in conjunction with an investment bank and independent engineer. (2005-2006)
- Completed financial advisory services to a private equity consortium on the successful acquisition of a gas-fired power generating facility. The engagement included evaluation of all revenue streams, confirmation of investment economics under alternative market scenarios, and support for negotiations on key terms. (2005)
- Engaged by Goldman Sachs to assist with the financial and industry due diligence associated with the acquisition of Zilkha Renewable Energy, a wind energy company with over 20 projects under development. (2005-2006)
- Engaged by the State of Vermont to study of the feasibility of acquiring 550MW of hydroelectric generation facilities from USGen-New England. Completed a valuation of the assets, researched financing options with alternative tax-exempt and taxable structures, monitored the status of NEG's bankruptcy proceedings, researched comparable large-scale municipalizations, studied the potential in-state and out-of-state uses for the power, and tested the market for power sales to regional utilities. Facilitated discussions with companies for equity partnership, as well as for the purposes of providing power marketing and O&M services to the project. In addition to in-house consulting staff, compiled a team of legal, engineering and financing experts to deliver a comprehensive work product reflecting all aspects of the risks and benefits of purchasing this unique set of assets out of bankruptcy. (2003-2004)
- Evaluated a major utility's unregulated energy services business units and advised management on valuation and the potential market for the businesses. Developed offering materials and represented the company in negotiations with a potential buyer. (2001-2002)
- Lead advisor in the auction of Conectiv's $875 million in fossil and nuclear electric generation assets to NRG, PSE&G, and Exelon. Provided expert testimony before the New Jersey Board of Public Utilities on the auction process and asset values. (1999-2002)
- Provided financial and market analysis to Provincial Auditor of Ontario in examination of the long-term lease arrangement for the Bruce nuclear facility between Ontario Hydro and British Energy. (2002)
- For a private equity firm, evaluated on investment in a manufacturer of electric generation equipment. Analyzed the company's sustainable technological advantage, interviewed major customers, assessed competitor positioning, and provided market and revenue projections for the investment evaluation. (1999)
- Served as technical and market advisor for an investment consortium in the evaluation of an investment in five cogeneration plants. Analyzed fuel and off-take contracts, regulatory risk, plant operating procedures, and management personnel. Provided revenue and cost projections, supported bank discussions, and assisted bid negotiations. (1998)

- Co-advisor to Sithe Energies in the auction of the company's North American assets to Reliant and Exelon, and the marketing of its assets in Australia and Asia. (1999-2000)
- Lead advisor in the electric restructuring, auction of generating assets, and long-term power contracting for Denton Municipal Electric. Conducted regular briefings for the City Council. (1999-2001)
- Co-advisor to Sierra Pacific Resources in the proposed auction of 3,000 MW of fossil generating assets. (1999-2000)
- Co-advisor to TXU in the proposed auction of 560 MW of fossil generating assets. (2000)
- Co-advisor to Boston Edison (NSTAR) in the auction of $536 million in fossil generating assets to Sithe Energy. (1997-1998)
- Co-advisor to GPU in the auction of $1.7 billion in fossil generating assets to Sithe Energy. (1997-1998)
- Lead advisor to Bangor Hydro Electric Company in the auction of $90 million in hydroelectric, transmission, and fossil generating assets to PP&L Global. (1998-1999)

Business Strategy Experience

- Retained by a major Canadian electric company to study the cross-border transmission constraints into U.S. power markets and identify strategic options and transmission investments for expanding capacity and energy flows into these markets. (2007)
- Retained by the Western Electric Coordinating Council's (WECC) Board of Directors to facilitate the development of the WECC's five-year strategic plan. WECC is one of eight regional electric reliability organizations in North America, with 180 members across 14 states, and portions of Canada and Mexico. Leading the effort for Concentric, the planning process entails interviewing key stakeholders, facilitating discussion within and across member groups, gathering and presenting research, and making recommendations to the Board on the Strategic Plan. (2007)
- Engaged by a Canadian based utility company to develop its business strategy for growth in the U.S. Working with senior management, providing both a "big picture" strategic assessment of driving forces and opportunities in distribution, transmission and generation, supported by more detailed evaluation of specific investment options for presentation and discussion with its Board. (2005-2007)
- Advisor to Cook Inlet Regional, Inc., an Alaskan Native corporation, for the purpose of developing wind energy projects within the State of Alaska. (2006)
- Advisor to Tamarack Energy, Inc., for the purpose of developing renewable energy projects in the Northeast U.S. (2006)
- Engaged by a major Japanese corporation to provide assistance with the strategic evaluation of its ability to enter the $400 billion power and gas trading market. Management in Tokyo and New York required an independent assessment of the new and complex U.S. market for power and natural gas, and a determination of the company's ability to successfully compete. (2005-2006)
- Retained by an international power company to assist with evaluation of its corporate strategy and financial performance. Evaluated the company's corporate strategy using modern portfolio management tools to determine the inherent risk/reward trade-offs in the company's business portfolio. Analyzed core drivers of movements in the company's stock price and assisted the management team with engaging the Board of Directors in a strategic evaluation of the company's electric business. (2004)
- Strategic advisor to a major Public Power Authority in its evaluation of alternative business strategies and organizational structure. Provided industry benchmarking and qualitative analysis of various public power models for the Authority and developed future industry scenarios. Collaborated with

team of legal and banking advisors in examining restructuring options to maximize benefits to the Authority's stakeholders. (2004-2005)

- Provided analysis for the FirstEnergy Board of Directors regarding the potential economic impact of the 2003 power outage. (2003)
- Provided a strategic assessment of an eastern utility's electric generation and marketing business. The strategic assessment included: analysis of wholesale and retail electric markets in PJM, NE and NY markets, capacity, energy and ancillary service products, transmission and congestion, customers for wholesale products, competitors, short-term and long-term financial measures of viability, and factors for success. The engagement involved brainstorming sessions with the client team, research and analysis, and concluded with a report and evaluation of the company's strategic options and business prospects. (2003)
- Developed a cost of capital and investment decision-making framework for the company's new business investments. (2002)
- Strategic advisor to a Mid-Atlantic Utility in the development and implementation of the company's generation and marketing business. (1999-2000)

PUBLICATIONS AND RESEARCH

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

SELECTED SPEAKING ENGAGEMENTS

- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998
- "New Market Dynamics," New England-Canada Business Council Annual Meeting, November 1996
- "Fuels Markets and Generation Choices," Electric Power Research Institute Seminar, Charleston, SC, October 1989
- "Issues Underlying the Long-Term Outlook for Natural Gas Markets," International Association for Energy Economics' International Conference, Calgary, Canada, July 1987

PROFESSIONAL HISTORY

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

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

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

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

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

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

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

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

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

EDUCATION

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

DESIGNATIONS AND AFFILIATIONS

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

Julie Lieberman
Project Manager

Ms. Lieberman is a financial and economic consultant with over 25 years of experience in the energy industry. Her broad base of experience includes: financial and economic consulting in the energy sector, utility ratemaking, regulatory policy and compliance, due diligence and litigation support and analysis, risk management, asset valuation and modeling, wholesale and retail energy trading and operations, energy procurement and scheduling, and utility hedging strategies. She has performed a variety of economic analyses, extensive regulatory research and assisted in the preparation of testimony and research reports in both regulatory and non-regulatory proceedings. Ms. Lieberman has performed focused regulatory research on issues pertaining to cost of capital, consolidated tax savings adjustments, risk-mitigating rate mechanisms, and Dodd Frank legislation and its implications for the end-use energy sector. Ms. Lieberman is proficient in Microsoft Office applications, Crystal Ball, and SPSS and has used option modeling, Monte Carlo simulations, and VAR analysis in a variety of risk applications. Prior to joining Concentric, Ms. Lieberman served in the financial and risk related fields in the unregulated energy trading and marketing sector. She holds a Masters in Finance from Boston College, a B.S. in Accounting from Indiana University, is a licensed CPA (Texas), and is a FINRA licensed securities professional (Series 7, 63, and 79).

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation

Ms. Lieberman has assisted in the development of expert testimonies and analyses in a number of utility regulatory proceedings before state and provincial regulatory commissions, and the FERC in the areas of: cost of capital, consolidated tax savings, marginal cost, alternative regulation, prudence and regulatory policy. Specific analyses performed to determine the return on equity have included: Discounted Cash Flow analysis (perpetual growth and variable rate growth methods), CAPM analysis, Risk Premium analysis, Comparable Earnings analysis, multiple and single variable Regression Analysis; and analyses related to business risk and flotation costs. Ms. Lieberman has conducted in depth studies on disparities between rates of return in the U.S. and Canada for Canadian regulators and their constituents; and has assisted in developing a recommended framework for establishing rates of return in Canada. Ms. Lieberman has performed extensive analyses of specific business risks as they relate to cost of capital, including: demand elasticity and declining use per customer and risk mitigation measures embedded in utility rates; and has conducted in-depth research and analyses of jurisdictional regulatory environments and applicable precedents as they relate to cost of service and utility rate making.

Representative engagements have included:

- Provided in-depth research and drafted testimony on FERC policy towards rate of return for new transmission investment for the owners of a newly-constructed regulated transmission line. (2011, 2007)

- Performed research and analyses and assisted in development of testimony on jurisdictional treatment of consolidated tax savings in Texas for CenterPoint Houston. (2010)
- Assisted Climate Change Central of Alberta with extensive research regarding pertinent Alberta legislation and DSM funding mechanisms in other jurisdictions that may support rate-base funding for DSM and renewable programs in the Province, and documented findings in a Report. (2010)
- Provided written comments and analyses on behalf of Enbridge and participated in an expert panel before the OEB in the Board's consultative process to determine whether its cost of capital formula was generating reasonable returns in the context of the prevalent economic downturn. (2009)
- Assisted in the development of written testimony and analyses for Oncor regarding the return of and on capital, consolidated tax savings adjustments, merger effects, and changing business environments. (2008)
- Assisted with the preparation of comments on behalf of a consortium of Massachusetts electric and gas utilities in response to MA DPU inquiry on a generic decoupling measure. (2008)
- Performed regulatory policy research for Southwestern Public Service Co. on the precedent for consolidated tax savings adjustments in the U.S. and its implications on regulatory principles for determining fairness and utility cost of service. (2007)
- Assisted in the development of an automatic adjustment formula for Green Mountain Power's return on equity to be used in its Alternative Regulation Rate Plan. (2006)
- Performed extensive research and assisted in the development of testimony related to the prudence of OG&E's acquisition of the McClain generating facility and developed an accompanying white paper on competitive bidding practices in the U.S. (2005)

Risk Management

Ms. Lieberman has performed extensive research on emerging regulatory policy and legislation impacting the energy sector, specifically Dodd-Frank and the emergence of carbon markets in the U.S. In her regulatory and ratemaking assignments, she has advised clients on the mechanics of risk-mitigating rate mechanisms pertaining to decoupling and cost recovery. Ms. Lieberman has been engaged to assess the adequacy of system processes and controls from a risk perspective and has conducted a variety of analyses that include an assessment and quantification of risk. Ms. Lieberman served in the risk management and commodity procurement areas in the unregulated natural gas energy trading and marketing sector. In addition, while with Ernst & Young in Houston, Ms. Lieberman specialized in the audit of wholesale energy trading entities, marking trading books to market, and performing detailed internal control assessments for a number of large energy exploration, production, trading, and marketing concerns.

Representative engagements have included:

- Assisted a confidential utility client in supporting a regulatory challenge to their hedging activity by commission staff (DOC, Minnesota). The staff asked the Company to explain how they approached hedging with particular focus on the role of implied volatility in making hedging determinations. (2011)
- Assessed the likely dispatch and overall spark spread opportunity of a proposed generation facility in Connecticut; developed a solicitation for a power off-take agreement for a 10-15 year term and performed a quantitative evaluation of bid responses. (2008)
- Developed a model and rigorous analyses to assess the value of the optional take provisions of certain power purchase agreements and their associated swap contract hedges in support of expert

testimony on the issues of damages in connection with a failed transaction for the sale of a portfolio of power contracts. (2005)
- Assisted in the modeling and valuation of a portfolio of power purchase agreements held by National Grid, using independent Monte Carlo simulation models and forecast assumptions for a range of variables and scenarios. (2004)
- Assisted in the development of a model to estimate gas market price effects and damages attributable to the trading activity of a market participant suspected of gas market manipulation in the Western energy markets in the period from 2000-2001. (2004)

Litigation Support

Supported development of expert testimony in various energy related arbitrations. Issues addressed include, standards of conduct, and energy economics. Services provided also included, economic modeling, collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, and assisting in the preparation of written testimony.

- Performed research and analyses around the valuation impact of "Round Trip Trades" on a trading entity's IPO price in connection with a shareholder initiated litigation. Research involved extensive fact discovery in the proceeding, prevalence of wash trading in the industry, and exploration of prevailing valuation methodologies used by investment banks connected with the IPO. (2005)
- Performed extensive fact discovery, research and analyses in support of Shearman & Sterling/Merrill Lynch in a litigation against Allegheny Energy Supply, which led to the development of expert testimony on behalf of Merrill Lynch, relating to liability and damages for due diligence disclosures. (2004-2005)

Management and Operations Consulting

Ms. Lieberman possesses direct financial and operational experience in the natural gas and energy trading industries enabling the delivery of significant value to clients. Ms. Lieberman has conducted detailed internal control reviews for a variety of clients primarily in the energy production, marketing, distribution and mining sectors, focusing on understanding business processes and value drivers to help clients obtain objectives.

Representative engagements have included:

- Performed an assessment of a large gas LDC's gas operating system to identify where control deficiencies were present and provided recommendations to address deficiencies. (2010-2011)
- Directed a review of the accounting, risk, and reporting processes associated with a gas distribution utility's unregulated natural gas transactions; identified weaknesses and proposed solutions. (2008)

Transaction Related Financial Advisory Services

Ms. Lieberman has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative engagements have included:

- Assisted in the development of a valuation of desalination facilities in California for corporate accounting purposes. (2008)

- Validated valuation models for a portfolio of power purchase agreements against fuel supply and transportation contracts and steam sales agreements to assist in due diligence in an acquisition of generating projects. (2007 – 2008)
- Assisted in auction for the sale of the Palisades nuclear power plant. (2006)
- Assisted in auction for the sale of the Masspower gas-fired power plant. (2005)

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
Project Manager
Senior Consultant

Green Pasture Software, Inc. (2001 – 2004)
Controller

AllEnergy Marketing Co., LLC (1997 – 2001)
Energy Analyst

Global Petroleum Corp. (1992 – 1997)
Director of Transportation Operations

Ernst & Young (1989 – 1992)
Audit Manager

Pennzoil Company (1984 – 1989)
Internal Auditor

EDUCATION AND CERTIFICATIONS

M.S., Finance, Boston College, with Honors, 2003
B.S., Accounting, Indiana University, 1984

Licensed Securities Professional: NASD Series 7, 63, and 79 Licenses
Certified Public Accountant, Houston, TX, 1986

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Treasurer, New England Women in Energy and Environment

PUBLICATIONS/PRESENTATIONS

- "Hedging Under Scrutiny, Planning ahead in a low-cost gas market." (with Julie Ryan), Public Utilities Fortnightly, February 2012

- "Rates of Return for New Transmission Build in the US and Canada." Presentation to the Canadian Electricity Associations Transmission Workshop, February 2009.
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with James Coyne and Dan Dane), prepared for the Ontario Energy Board, June, 2007.

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

CME, CCC, SEC, VECC INTERROGATORY #6

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

On page 3, Concentric indicates that EGDI's current common equity ratio does not satisfy the financial metrics for an A- or above rating and is not sufficient to ensure that EGDI will continue to meet its forecast coverage ratios and debt covenants.

a) Does any rating agency place 100% reliance on "financial metrics"?

b) Is EGDI currently rated A (Stable) by DBRS?

c) When, if ever, was EGDI rated *below* A by DBRS?

d) Please provide a table with the financial metrics for EGDI from 2006 to the present with the DBRS bond rating for each year.

e) Is there any legal requirement for EGDI to finance with MTNs, where the 2.0X interest coverage covenant restriction exists?

f) Does the 2.0X interest coverage covenant restriction prevent EGDI from issuing first mortgage bonds, preferred shares, or Commercial Paper ("CP") swapped into longer term fixed rate debt?

RESPONSE

a) Concentric affirms that rating agencies do not place 100% reliance on "financial metrics".

b) Yes.

c) Please see the response to CME, CCC, SEC, VECC Interrogatory #2, filed at Exhibit I, Tab E2, Schedule 21.2.

Witnesses: J. Coyne
J. Lieberman
Concentric
M. Lister
D. Yaworski

d) Please see the table below:

($ Millions)	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual
Equity Thickness	35%	36%	36%	36%	36%	36%
Earnings to Common Shareholders (After ESM)	$ 130	$ 140	$ 135	$ 140	$ 140	$ 138
Cash Flow	$ 340	$ 368	$ 372	$ 392	$ 408	$ 415
EBIT	$ 383	$ 396	$ 393	$ 388	$ 378	$ 349
EBITDA	$ 593	$ 624	$ 630	$ 639	$ 645	$ 626
Interest Expense (Deemed)	$ 161	$ 159	$ 162	$ 153	$ 151	$ 142
Total Assets (RateBase)	$ 3,593	$ 3,628	$ 3,779	$ 3,794	$ 3,838	$ 3,957
Short Term Debt (incl. Current Portion)	$ 208	$ 33	$ 7	$ 148	$ 165	$ 113
Long Term Debt	$ 2,028	$ 2,189	$ 2,312	$ 2,180	$ 2,191	$ 2,320
Preference Shares	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100
Equity	$ 1,258	$ 1,306	$ 1,361	$ 1,366	$ 1,382	$ 1,425
Interest Coverage	2.4	2.5	2.4	2.5	2.5	2.5
Debt /EBITDA	3.8	3.6	3.7	3.6	3.7	3.9
FFO/Interest	3.1	3.3	3.3	3.6	3.7	3.9
FFO/Avg. Debt	15.2%	16.6%	16.0%	16.8%	17.3%	17.1%
Debt to Capitalization	62.2%	61.2%	61.4%	61.4%	61.4%	61.5%
Capital Expenditures	364.6	354.9	366	349.1	337.6	399.2
DBRS Unsecured Debentures & Medium-Term Notes Rating	A	A	A	A	A	A

Notes:
2008-2011 Earnings includes ESM
Table developed by EGDI

e) No, there is no legal requirement for EGD to finance with MTNs, where the 2.0X interest coverage covenant restriction exists.

f) The times interest coverage restricts EGDI from issuing medium term notes and commercial paper unless the proceeds are being used to retire similar, existing obligations of the company. First Mortgage Bonds and preferred shares are excluded from the interest coverage covenant restriction.

Witnesses: J. Coyne
J. Lieberman
Concentric
M. Lister
D. Yaworski

CME, CCC, SEC, VECC INTERROGATORY #7

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

On page 7, Concentric discusses its procedure for generating proxy groups.

a) Please indicate why Concentric considers it important to have energy holding companies in the proxy group.

b) Please explain why Canadian Utilities, Emera, Fortis, Valener and Veresen are not used as Canadian comparables.

c) Please comment on any differences in risk between holding companies and operating companies.

RESPONSE

a) In order to perform a DCF analysis or CAPM analysis, it is necessary to ascertain the market derived price of the company's stock. A direct market-based cost of capital analysis of EGDI as a stand-alone company is not possible since it is not publicly traded and is not followed by analysts. As an alternative, it is important to select a group of proxy companies that are most like EGDI, but that have stock prices, dividends, and growth rates to perform fundamental CAPM and DCF analyses. Holding companies are typically utilized to obtain these data, but they are not essential when the operating company is publicly traded.

b) Canadian Utilities, Emera, Fortis, and Veresen did not meet Concentric's screening criteria for comparability found on page 8 of our Report. At the time of Concentric's report, those screening criteria may be summarized as follows:

1. Must currently be publicly traded and paying quarterly dividends;
2. Must have an S&P credit rating greater than or equal to BBB and less than or equal to A+;

Witnesses: J. Coyne
J. Lieberman
Concentric

3. Must have at least 60% regulated revenues as a percent of total consolidated revenues;
4. Must have at least 60% of regulated revenues derived from natural gas distribution operations; and
5. The utility could not be party to a merger or acquisition.

Valener was a newly formed entity at the time Concentric had conducted its analysis with only a partial year's data for 2010. Since Concentric carried out its screening criteria on 3 years of history, i.e. 2008-2010, Valener was excluded. Beyond this initial lack of information to base a screening determination, Valener would otherwise satisfy the criteria for the proxy group, i.e. it meets the 5 criteria listed above. If it is desired, Concentric will provide an analysis including Valener in the proxy group.

Lastly, our corroborating proxy group of Canadian regulated utilities, which did include Emera, Fortis, and Canadian Utilities, was carried over from Concentric's prior analysis for EGDI in the 2009 Consultative Process on Cost of Capital.

c) The risk profile of a diversified holding company may vary markedly from that of its regulated subsidiary, depending upon the extent it is invested in unregulated ventures. Regulated and unregulated investments are subject to substantially different business risks and investor required returns. For these reasons, Concentric selects only those holding companies for the proxy group that are primarily comprised of regulated distribution utilities (60% of consolidated revenues, and 60% of regulated revenues comprised of gas distribution) to best align the risk profile of the proxy companies to the subject utility.

Witnesses: J. Coyne
J. Lieberman
Concentric

CME, CCC, SEC, VECC INTERROGATORY #8

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

On page 9, Concentric discusses its ROE analysis.

a) On page 10, Concentric indicates that in 2009 its recommended ROE was 10.50% but a similar analysis today indicates 10.83%. Please indicate the current and forecast level of the long Canada bond yield at the time of the 2009 analysis and that for the current report.

b) Please compare the level of stress in the Canadian financial system today with 2009.

c) Please provide a table with the actual and allowed ROE for each of the 7 US comparables, and for EGDI, for each year since 2006.

d) Please confirm that capital market conditions in the US and Canada are different as indicated by the 0.74% difference in government bond yields (footnote 12).

RESPONSE

a) Please see the table provided on the following page.

Witnesses: J. Coyne
J. Lieberman
Concentric

	July 16, 2009 Consensus Economics (Prior Report)	October 2011 Consensus Economics (Current)
Authorized Return at 40% Equity	**10.50%**	**10.83%**
Most Recent Year 10-year Long Bond	**3.3%**	**2.2%**
10-year Long Bond 3-mos out	3.5%	2.3%
10-year Long Bond 12-mos out	3.8%	2.6%
Average Forecast Long Bond	3.65%	2.45%
Current Spread (10 v 30-year)	0.53%	.61%
Forward-Looking 30-Year Long Bond	**4.18%**	**3.06%**
LT Forecast 10-year Long Bond Yield	4.75[1]%	3.95[2]%
Current Spread (10 v 30-year)	.53%	.61%
Long-term Forecast Long-Bond	**5.28%**	**4.56%**

b) The 2009 Consultative Process occurred in the midst of the Global financial crisis. Although the Canadian economy has been somewhat slow to recover from the global recession, domestic demand and personal spending are growing. The recovery in the U.S. economy has driven growth in Canadian fuel exports, which typically account for approximately 74% of total Canadian exports. Positive signs of recovery may be observed in a declining unemployment rate, strong rebound in the

[1] 2011 - 2016 Forecast mid-point per Consensus Economics Forecast, October 12, 2009.
[2] 2013 – 2018 Forecast mid-point per Consensus Economics Forecast, October 10, 2011.

Witnesses: J. Coyne
J. Lieberman
Concentric

oil and gas extraction industry, and easing concerns about the global economy. Nonetheless, the Euro zone crisis and the slow-down in the Chinese economy and their anticipated impact on exports have dampened the optimism.

The Canadian financial system has experienced an ongoing flight to quality in the wake of the financial crisis as evidenced by ever decreasing treasury yields. This indicates greater aversion to risk on the part of investors as financial regulators have responded to the credit crisis and financial market dislocation by providing supportive monetary policy. Those low interest rates on government bonds reflect the risk aversion in global financial markets, as investors expressed preference for the relative safety of government bonds over the risks associated with equity ownership. In summary, individually, certain economic indicators show some improvement, yet the overall economy is only slowly showing signs of recovery.

c) Tables providing the actual and allowed ROE for the subsidiary operating companies of the 7 US comparables are presented on the following pages. For a presentation of EGD's actual and allowed ROE, please refer to CME, CCC, SEC, VECC Interrogatory # 1, filed at Exhibit I, Tab E2, Schedule 21.1.

Authorized ROE

Company	**State**	**12/31/ 2006**	**12/31/ 2007**	**12/31/ 2008**	**12/31/ 2009**	**12/31/ 2010**	**12/31/ 2011**
National Fuel Gas Distribution Corp.	NY	10.40%	9.10%	9.10%	9.10%	9.10%	9.10%
National Fuel Gas Distribution Corp.	PA	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Northwest Natural Gas Co.	OR	10.20%	10.20%	10.20%	10.20%	10.20%	10.20%
Northwest Natural Gas Co.	WA	NA	NA	10.10%	10.10%	10.10%	10.10%
Indiana Gas Co.	IN	10.60%	10.60%	10.20%	10.20%	10.20%	10.20%
Southern Indiana Gas & Electric Co.	IN	10.50%	10.15%	10.15%	10.15%	10.15%	10.15%
Vectren Energy Delivery Ohio	OH	10.60%	10.60%	10.60%	10.60%	10.60%	10.60%
Piedmont Natural Gas Company, Inc.	NC	11.30%	11.30%	10.60%	10.60%	10.60%	10.60%
Piedmont Natural Gas Company, Inc.	SC	12.60%	12.60%	12.60%	12.60%	12.60%	12.60%
Piedmont Natural Gas Company, Inc.	TN	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Witnesses: J. Coyne
J. Lieberman
Concentric

Questar Gas Company	UT	11.20%	11.20%	10.00%	10.00%	10.35%	10.35%
Southern California Gas Company	CA	11.00%	11.00%	10.82%	10.82%	10.82%	10.82%
San Diego Gas & Electric	CA	11.85%	11.85%	10.70%	10.70%	10.70%	10.70%
Mobile Gas Service Corp.	AL	13.60%	13.60%	13.60%	13.60%	13.60%	13.60%
Southwest Gas Corp.	AZ	9.50%	9.50%	10.00%	10.00%	10.00%	9.50%
Southwest Gas Corp.	CA	10.90%	10.90%	10.50%	10.50%	10.50%	10.50%
Southwest Gas Corp.	NV	10.50%	10.50%	10.50%	10.15%	10.15%	10.15%
Average		*11.08%*	*10.98%*	*10.72%*	*10.70%*	*10.72%*	*10.69%*

Witnesses: J. Coyne
J. Lieberman
Concentric

Earned ROE

Company	State	12/31/ 2006	12/31/ 2007	12/31/ 2008	12/31/ 2009	12/31/ 2010	12/31/ 2011
National Fuel Gas Distribution Corp.		8.77%	10.38%	11.59%	10.86%	12.65%	13.00%
Northwest Natural Gas Co.		10.58%	12.53%	11.06%	11.38%	10.48%	8.94%
Indiana Gas Co.		7.29%	7.14%	9.24%	9.43%	9.40%	12.16%
Southern Indiana Gas & Electric Co.		8.36%	9.88%	9.38%	7.92%	9.61%	9.66%
Vectren Energy Delivery Ohio		2.78%	3.26%	3.60%	3.97%	3.96%	8.82%
Piedmont Natural Gas Company, Inc.		9.76%	10.41%	12.16%	12.79%	12.72%	11.68%
Questar Gas Company		11.24%	10.99%	10.46%	10.42%	10.56%	10.19%
Southern California Gas Company		15.29%	15.95%	16.71%	15.74%	14.85%	13.29%
San Diego Gas & Electric		12.64%	13.07%	13.52%	12.73%	12.04%	11.66%
Mobile Gas Service Corp.		12.09%	13.37%	12.28%	13.32%	12.52%	13.88%
Southwest Gas Corp.		9.30%	8.46%	5.87%	7.94%	8.90%	9.16%
Average		*9.83%*	*10.49%*	*10.54%*	*10.59%*	*10.70%*	*11.13%*

Sources: SNL Financial, LDC Filings

Witnesses: J. Coyne
J. Lieberman
Concentric

d) On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation. At the time of this response, the 10-year Canadian long bond is approximately the same as its U.S. counterpart, i.e. 1.7% versus 1.6% for the U.S[3]. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely, when compared against other developed and developing countries.[4] Based on these metrics and qualitative assessments, it is reasonable to conclude that over the long term, a reasonable investor would expect comparable returns from the two countries and that capital market conditions are highly correlated due to the close integration of the two economies.

[3] Consensus Economics, July 9, 2012.
[4] "World Investment Prospects to 2011", Economist Intelligence Unit, written with the Columbia Program on International Development, 2007 Edition, at pp. 38, 39, 235, provides a ranking of the world's largest economies based on a range of factors impacting the business environment. This report is produced in conjunction with the Columbia University Program on International Development. According to the report, "The business rankings model measures the quality or attractiveness of the business environment in the 82 countries covered by Country Forecasts using a standard analytical framework. It is designed to reflect the main criteria used by companies to formulate their global business strategies, and is based not only on historical conditions but also on expectations about conditions prevailing over the next five years." … "The business rankings model examines [91 indicators] in ten separate criteria or categories, covering the political environment, the macroeconomic environment, market opportunities, policy towards free enterprise and competition, policy towards foreign investment, foreign trade and exchange controls, taxes, financing, the labor market and infrastructure." The business environment ranks are updated annually in individual country forecasts. Based on the April 2012 update, which provides both the historical 2007-2011 rank and the projected 2012-2016 rank, Canada and the U.S. are ranked 4th and 5th respectively over the historic period, and 5th and 9th over the projected five years. The numeric country rankings for Canada and the U.S. are within 0.1% in the historic period and 0.6% in the forecast period. This report suggests that from a business investment perspective, Canada and the U.S. are highly comparable in a global context.

Witnesses: J. Coyne
J. Lieberman
Concentric

CME, CCC, SEC, VECC INTERROGATORY #9

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

On page 13, Concentric discusses the Board's capital structure methodology for gas distribution utilities and notes the EGDI request for 38% common equity in 2006, and the Board's determination of an equity ratio of 36% for EGDI, being a ratio that Union Gas Limited ("Union") had already accepted as reasonable.

a) Please produce a copy of the evidence of Dr. Carpenter and provide a list of the risk factors that EGDI put forward at that time and advise whether any of them have increased or decreased since that date.

RESPONSE

a) The evidence Dr. Carpenter produced in 2006 is attached. For the risk factors that EGD put forward and changes since that time, please refer to CME, CCC, SEC, VECC Interrogatory # 3, filed at Exhibit I, Tab E2, Schedule 21.3, part f).

Witnesses: R. Fischer
M. Lister

WRITTEN EVIDENCE

OF

PAUL R. CARPENTER

FOR

ENBRIDGE GAS DISTRIBUTION INC.

The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138
617.864.7900

August 2006

WRITTEN EVIDENCE OF
PAUL R. CARPENTER

TABLE OF CONTENTS

WRITTEN EVIDENCE OF
PAUL R. CARPENTER

I. OVERVIEW/SUMMARY

Q1. Please state your name, address and position.

A1. My name is Paul R. Carpenter. I am a Principal of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Massachusetts, Washington D.C., San Francisco, Brussels, Belgium and London, England. My office is located at 44 Brattle Street, Cambridge, Massachusetts 02138.

Q2. Will you briefly describe your educational background and professional qualifications?

A2. Yes. I am an economist specializing in the fields of industrial organization, finance and energy and regulatory economics. I received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University. I have been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for twenty years. I frequently have testified before federal, state and Canadian regulatory commissions, in federal court and before the U.S. Congress, on issues of pricing, competition and regulatory policy in these industries. Outside of North America, I have advised governments and regulatory bodies on the structure of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the U.K. Monopolies and Mergers Commission and the Australian Competition Tribunal, and advice to the governments of, and regulators in, Greece, Ireland, the Netherlands, New Zealand and Australia.

For at least 15 years I have been extensively involved in the evaluation of the economics and regulation of the natural gas industry in North America. In Canada, I have advised pipeline companies and have previously testified before the National Energy Board ("NEB") and the Alberta Energy and Utilities Board on matters relating to pipeline competition and capacity expansion, including the Alliance Pipeline Ltd. certification proceeding. I gave evidence on business risk previously before the NEB in the multi-pipeline cost of capital case, on behalf of Foothills Pipe Lines, and in more recent NEB proceedings on behalf of TransCanada PipeLines Limited. In January 2006, I provided written evidence on business risk before the Ontario Energy Board ("OEB" or "Board") on behalf of Union Gas Limited as part of Union's application for rates applicable to its storage, transmission, and distribution services. Further details of my educational and professional background, as well as a listing of my publications, are provided in my curriculum vitae, which is appended to this testimony as Attachment A.

Q3. What is the purpose of your evidence in this proceeding?

A3. My evidence evaluates whether there has been a change in Enbridge Gas Distribution Inc.'s ("the Company's") business risk since 1993 that would warrant a change in the deemed equity thickness authorized by the Board for the Company.

Q4. What is the basis for the 1993 reference date for this evaluation?

A4. It is my understanding that 1993 corresponds to the last time the Board considered a change in the Company's equity thickness that involved an evaluation of the Company's business risk. In EBRO 479 for the 1993 test year, the Board considered the Company's business risk in deciding to leave its equity thickness unchanged at 35%. It is my understanding that the Board has not evaluated the Company's business risk since EBRO 479. In particular, in its most recent 2004 decision involving the Company's cost of capital, the Board stated that it only evaluated changes in capital market conditions, and not business risk.[1]

Q5. Could you summarize your conclusions?

A5. Yes. My analysis indicates that equity investors would consider investment in the Company to be significantly more risky today than it was in 1993. I have identified four sources of this increased risk:

1) The business risk of the Company's gas distribution services have increased because they are now exposed to additional uncertainty due to changes in the commodity

1 Ontario Energy Board, Decision and Order in the Matter of Applications By Union Gas Limited and Enbridge Gas Distribution Inc. for a Review of the Board's Guidelines for Establishing Their Respective Return on Equity, RP-2002-0158, January 16, 2004, paragraph 114.

market for natural gas. The commodity market environment has changed markedly from the pre-1999 days of constrained pipeline outlet capacity from Western Canada and low wholesale prices to today's world in which Canadian prices are now "connected" to the rest of the North American market. In addition, the Company and its customers are now facing extremely high and volatile prices that are beginning to be reflected in declining gas usage per customer. Industrial demand for gas, in particular, is susceptible to the high and volatile wholesale price regime. More uncertain future utilization of the Company's distribution assets translates to higher business risks.

2) The Company's distribution assets are now at an increased risk of bypass by competitive suppliers than they were in 1993. This increased risk is indicated by the increased uncertainty surrounding the future application of Board policy toward bypass as reflected in the Board's recent approval of GEC's application to build a bypass pipeline in Union Gas Limited's service territory, as well as Union's application to serve the same facility.

3) The market risks associated with new gas-fired power generation demand in Ontario are currently very uncertain as to the extent of new capacity that might be required, when it will require new gas infrastructure, the competition to provide that infrastructure and its associated capital requirements.

4) Finally, there is significant uncertainty as to the future rate regulation framework that will be applied to the Company's distribution business. This is best reflected in the myriad of issues regarding rate regulation before the Board as a result of the Natural Gas Forum process.

Q6. How is the rest of your evidence organized?

A6. I begin by discussing the concept of business risk and how it relates to the cost of capital for a rate regulated firm. Then I describe the business risk environment in which the Company operates in terms of each of the elements of business risk. Finally, I evaluate whether there have been significant changes in the business risk of the Company since the Board last evaluated the issue in 1993.

II. DETERMINANTS OF BUSINESS RISK AND THE COST OF CAPITAL

Q7. How does one define business risk in the context of a company's cost of capital?

A7. Business risk in the context of a company's cost of capital is the uncertainty in the income earning capability of the firm's assets that investors in the company's equity are exposed to over the economic lifetime of the assets. Business risk has been traditionally subdivided into market demand, supply, regulatory and operating risks.[2]

Q8. What kinds of risks matter the most in evaluating a company's business risk from a cost of capital perspective?

A8. The risks that matter the most from an equity investor's perspective are those that cannot be diversified away through the holding of a broad portfolio of securities. Risks that are hard to diversify are those that are generally correlated with the level of (and changes in) general economic activity. Such risks are referred to as "systematic." Broadly speaking, systematic risks associated with the gas distribution business include uncertainties in the demand for, and supply of, distribution services that are affected by changes in economic activity, including incomes and prices.

Q9. How does the fact that a company itself may be comprised of a diversified portfolio of businesses affect the evaluation of a company's business risk?

A9. Investors in a company that contains a diversified set of businesses will evaluate the total business risk of the company based on the weighted average risk of the portfolio of assets that makes up the company, where the weights are the market value shares of the individual businesses in the overall company portfolio. Investors will not view a company as less risky simply because the company has chosen to own a diversified set of assets. This is because investors themselves can always choose to diversify within their own investment portfolios, and therefore no additional risk-reduction value is assigned to a company that chooses to diversify.

2 National Energy Board, Reasons for Decision, TransCanada Pipelines Limited, RH-4-2001, June 2002, page 13.

Q10. How does rate regulation affect a company's business risk?

A10. On the one hand, rate regulation reduces a company's business risk if it provides equity investors some assurance that a fair return on and of capital will be earned over the lifetime of the firm's assets. On the other hand, regulation may enhance a company's business risk if investors perceive that there is uncertainty in the future regulatory treatment of the firm's businesses. That is why regulatory risk is traditionally evaluated as a separate component of business risk. While the equity securities of rate regulated firms are generally perceived as relatively stable, low-risk investments, the greater exposure of such firms to competition from other regulated and unregulated businesses has changed that perception somewhat in recent years, particularly in the energy utility sector.

III. THE COMPANY'S BUSINESS RISK ENVIRONMENT

Q11. How would you characterize the Company's assets from a business risk perspective?

A11. The Company's assets are devoted to the provision of traditional gas distribution services to residential, commercial and industrial customers. While the Company owns significant storage assets, the vast majority of these assets are committed to meeting the needs of its in-franchise customers.

Q12. How does the Company's gas distribution business subdivide in terms of customer classes?

A12. The Company serves almost 1.8 million general service customers and almost 2,600 contract service customers. Its general service market is subdivided into two rate classes: Rate 1, which represents the residential rate sector, and Rate 6, which represents the apartment, commercial and industrial rate sectors. Rate 1 accounts for 92 percent of general service customers and 59 percent of general service throughput volumes, while Rate 6 accounts for 8 percent of customers and 41 percent of throughput volumes. The Company is forecasting general service throughput of 7,626 10^6m^3 for calendar year 2007, which represents a slight (0.6 percent) increase from the prior year estimate (the

2006 Bridge Year estimate) on a comparable weather-normalized basis. This slight increase in general service throughput is attributed to customer growth, partially offset by a decline in average use per customer of 1.8% percent per year for Rate 1 customers and 0.7% per year for Rate 6.

Q13. How does the Company earn income on its distribution services?

A13. The Company's distribution rates are established on a cost-of-service basis for a future "test year." As a result, its earnings depend on how actual results compare with the assumptions underlying its rates, particularly the assumptions with respect to costs and throughput. In addition, since 2000 the Company's earnings have been governed by various performance-based ratemaking (PBR) and earnings sharing mechanisms from time to time. As I discuss below, there is continued uncertainty as to the exact form of rate regulation that will apply to the Company in the future.

Q14. What types of storage services does the Company provide and how is income from those services derived?

A14. The Company owns and operates storage facilities with capacity of approximately 105,000 TJ (98 Bcf). The vast majority of this storage capacity is committed to in-franchise customers.[3] In addition, beginning April 1, 2006 the Company has three storage contracts with staggered terms with Union Gas Limited. These three contracts have total capacity of approximately 21,300 TJ, and are also committed to in-franchise customers. The Company recovers from in-franchise customers the costs it incurs to operate and contract for storage on their behalf. The Company offers Transactional Services ("TS") to trade short-term storage and transportation capacity that is not required to meet the needs of its in-franchise customers. Pursuant to the Board's decision in EB-2005-0001/EB-2005-0437, the Company is permitted to recover its estimated O&M costs for providing TS from ratepayers. TS margins are shared with ratepayers as follows. Ratepayers are guaranteed at least $8 million in revenues from TS gross margin. Thus, if the Company generates less than $8 million in TS gross margin, the shareholders

3 A small amount (approximately 2,100 TJ (2 Bcf)) is contracted to third parties.

must make up the deficit between actual gross margins and the $8 million in guaranteed margins to ratepayers. The Company retains TS gross margins between $8 million and $10.7 million. TS gross margins above $10.7 million are shared between ratepayers and the Company, with 75% going to ratepayers and 25% going to the Company.

Q15. Is the Company continuing to make capital investments in its distribution business?

A15. Yes. The Company is proposing capital expenditure of $474.4 million for calendar year 2007. This includes $301.3 million in “business as usual” expenditures (such as customer related distribution plant expenditures), $50.2 million in safety and integrity initiative expenditures (including expenditures associated with the Company’s accelerated cast iron main replacement project), $37.0 million in expenditures associated with leave to construct projects (such as those associated with the Portlands Energy project and the Sithe Goreway project), and $85.9 million in expenditures for other initiatives (such as customer information system, automated meter reading and underground storage initiatives). The Company estimates total capital expenditures of $389.9 million for calendar year 2006, compared with the Board approved capital budget of $300 million. The Company continues to put new capital at risk.

Q16. Does the fact that the markets the Company serves are expected to grow mean that its assets are likely to be exposed to less business risk?

A16. No. Risk is not about expectations alone. Risk involves the *uncertainty* associated with the expected outcomes. Some of the riskiest firms that one can evaluate from an investment perspective are those that serve high growth but highly uncertain markets such as telecommunications or technology. A high growth market is certainly a positive factor from an equity investor’s perspective *all else equal*. However, that same investor will demand a higher rate of return if the expected growth is more uncertain.

Q17. What are the principal classes of business risk to which the Company is exposed?

A17. The Company is exposed to market risk in its gas distribution business. The Company is also exposed to regulatory risk, particularly given that there is currently substantial uncertainty over the future regulatory regime that will apply to the Company's regulated business.

Q18. How does market risk manifest itself in the Company's gas distribution business?

A18. The market risk to which the Company is exposed in its distribution business manifests itself in uncertainty over the future utilization of its distribution assets. Because the Company's gas distribution assets are sunk investments, and cannot be redeployed easily to another use should market conditions change, the Company's future income earning capability depends critically on the maximum utilization of its assets. While the Company has a regulated distribution monopoly in its franchise area, regulation does not provide the Company with assured cost recovery protection should its asset utilization differ from its forecasts. In this way, the Company bears some market risk that depends on asset utilization.

Q19. What factors could affect the utilization of the Company's distribution assets?

A19. Distribution asset utilization is a function of the wholesale and retail price of the gas commodity itself, of competing fuels (particularly in the industrial customer class), of general economic activity in its service area, and of weather deviations from normal forecast conditions. Of these risk factors, the ones most important to equity investors (i.e., those that are systematic) are the level of prices and economic activity. Weather deviations from normal, while an important uncertainty for the Company, are less important to equity investors because they are not likely to be correlated with the market and hence they are a diversifiable risk. Again, this is because investors themselves can cheaply diversify away risks that are not correlated with movements in the general economy by holding a portfolio of equities, such as broadly-based mutual funds.

Q20. To this point you have not mentioned supply risk. Does the Company face supply risk in its gas distribution business?

A20. Not to a significant degree, in my opinion. This is partly because the Company's gas supply costs are a pass-through item in its customers' bills. Of course, to the extent these supply costs rise, the market risk to which the Company is exposed increases, as I describe below. But that is not the same as supply risk in that the Company does not face a significant risk that the utilization of its facilities will be reduced due to the *unavailability* of supply. The Company has access to gas supplies from a wide variety of supply sources and from a major, liquid hub at Dawn, Ontario.

IV. EVIDENCE OF CHANGES IN THE COMPANY'S BUSINESS RISK

Q21. What changes in the business risk to which the Company is exposed since 1993 have you identified?

A21. I have identified four areas in which there has been a measurable increase in the Company's business risk that would matter to investors in its equity securities. These are: 1) Increases in the level and volatility of gas commodity prices and thus increased uncertainty in use per customer; 2) Increased potential for bypass of the Company's distribution system; 3) Uncertainty in the growth of gas-fired power generation; and 4) Heightened regulatory uncertainty associated with the rate regulation framework applied to the Company's distribution business.

A. INCREASES IN THE LEVEL AND VOLATILITY OF GAS COMMODITY PRICES AND UNCERTAINTY IN GAS USE PER CUSTOMER

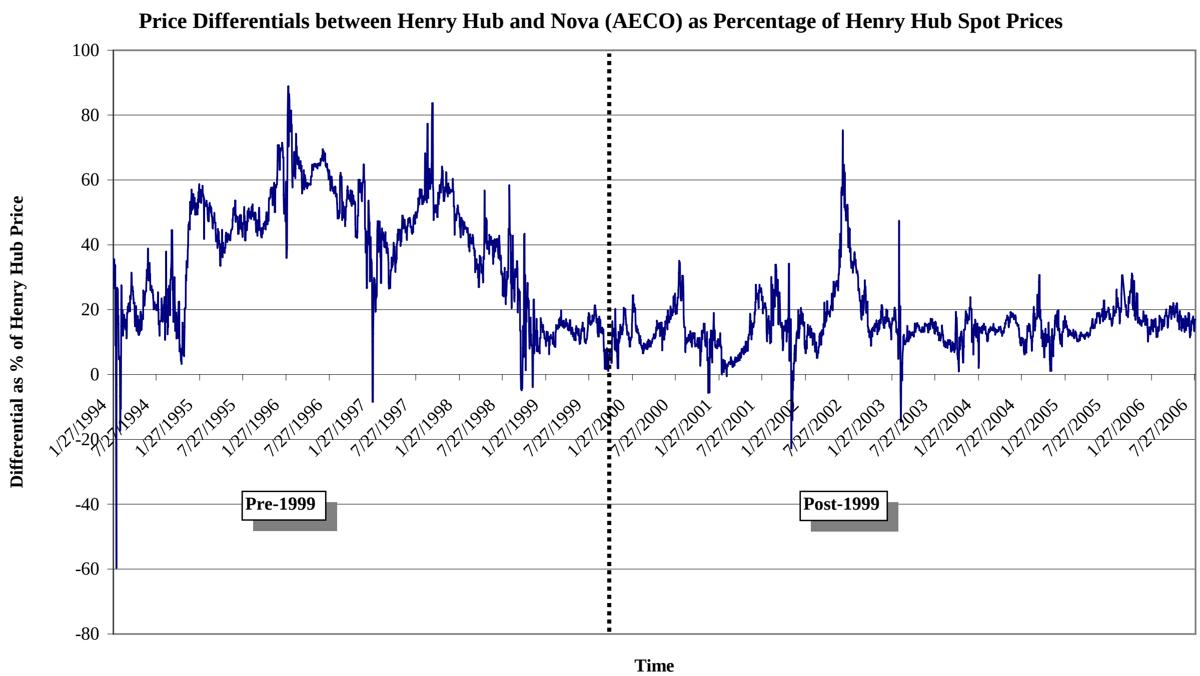
Q22. Is the current natural gas commodity market in which the Company operates different today than it was in 1993?

A22. Yes. The Company is operating in a significantly different gas commodity market today than it was in 1993. In 1993, the Western Canadian Sedimentary Basin ("WCSB") was entering into a period of rapid growth in productive capacity. At that time, the principal market concern was whether pipelines could be built or expanded rapidly enough to move that supply to eastern markets. Those market conditions persisted until about 1999. By 1999, consumers of Western Canadian gas were coming to the end of a multi-year period in which the price of gas from the WCSB was "disconnected" from (i.e., lower than) the market price of gas from other North American sources. This occurred because growth in WCSB production had outstripped the pipeline capacity available to deliver that gas to the market. Thus, if your gas supplier had access to the WCSB (as the

Company did), you were enjoying a period in which natural gas was very cheap in absolute and relative terms, with a significant competitive advantage over other energy sources.

That era came to an end with the completion of the TransCanada expansion projects and the construction of the Alliance and Vector systems that went on line in 1999. Instead of too little pipeline capacity out of the WCSB, the market was entering a prolonged period of excess capacity out of the basin. At that point, the price of WCSB gas reconnected with the North American market and it has been connected ever since. This change in the relative prices of WCSB gas and the market price of gas from other sources (as represented by the market price at the Henry Hub) is shown in Figure 1.

Figure 1



Notes: Null prices are omitted to adjust for inactivity.
Price differentials are calculated as Henry Hub spot prices minus Nova (AECO) spot prices.

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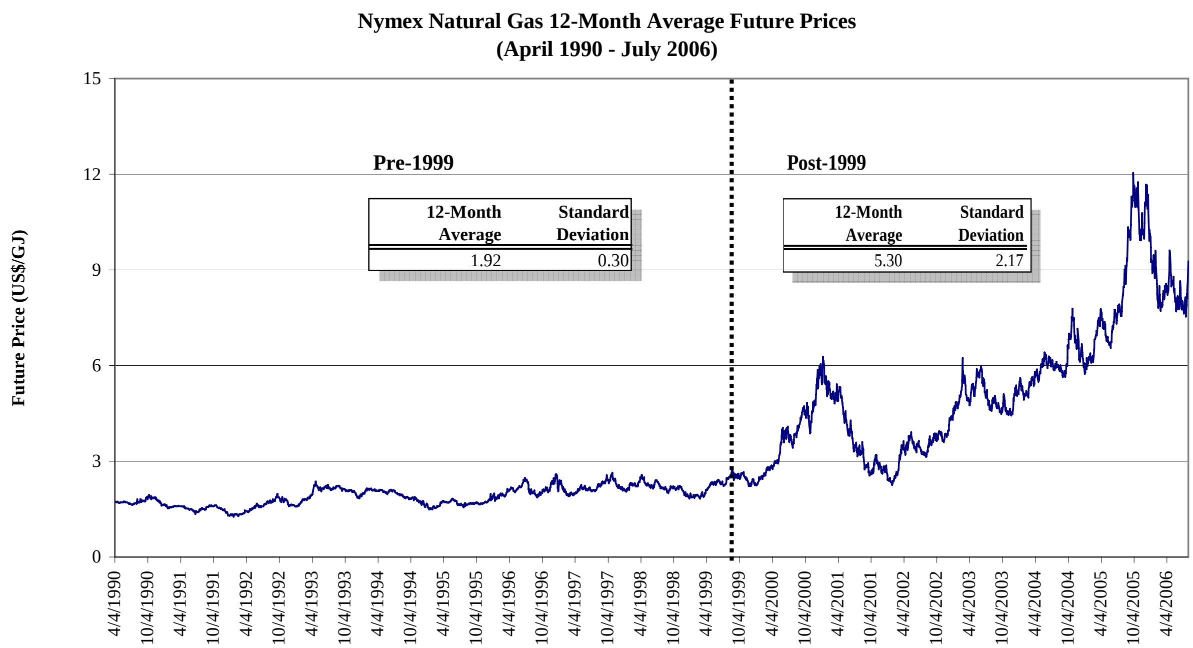
Q23. Is this the only change in the gas commodity market since 1993 worth noting?

A23. No. If anything the changes just described merely set the stage for the participation of the Company, its customers and investors in the even more dramatic increases in the market price and volatility of natural gas experienced since 2000. To show this phenomenon, in Figure 2 I have plotted the 12-month forward "strip" price of natural gas on the New York Mercantile Exchange (NYMEX) from April 1990 to July 2006. This is a useful index to refer to because it reflects the broad market expectation of the level and volatility of future prices in a way that is normalized somewhat for seasonal effects.

Figure 2

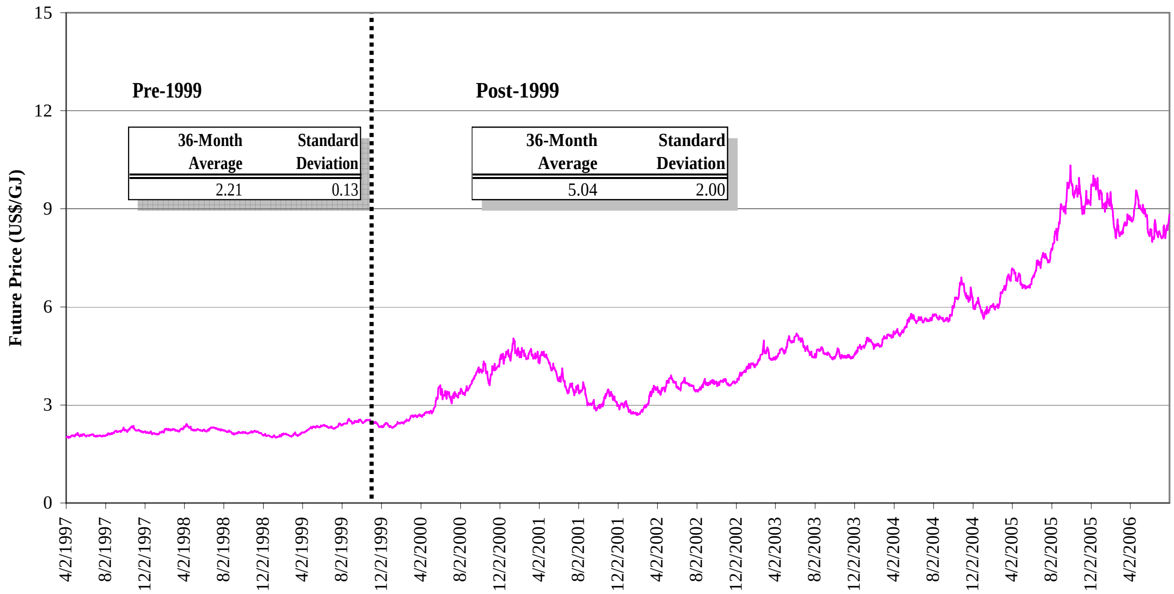


Note: Null prices are omitted to adjust for market inactivity.

Prior to 1999 the average of these forward prices was US $1.92 per GJ with a standard deviation of $0.30, a very low and stable environment. (And recall that consumers of WCSB gas enjoyed an even more favourable environment than this during the latter part of this period.) As the figure indicates, since 1999 the average forward price more than doubled to US $5.30 per GJ and the standard deviation of those prices ballooned to $2.17, a seven-fold increase. The same pattern can be seen for 36-month NYMEX forward prices shown in Figure 3.

Figure 3

Nymex Natural Gas 36-Month Average Future Prices (April 1997 - July 2006)



Note: Null prices are omitted to adjust for market inactivity.

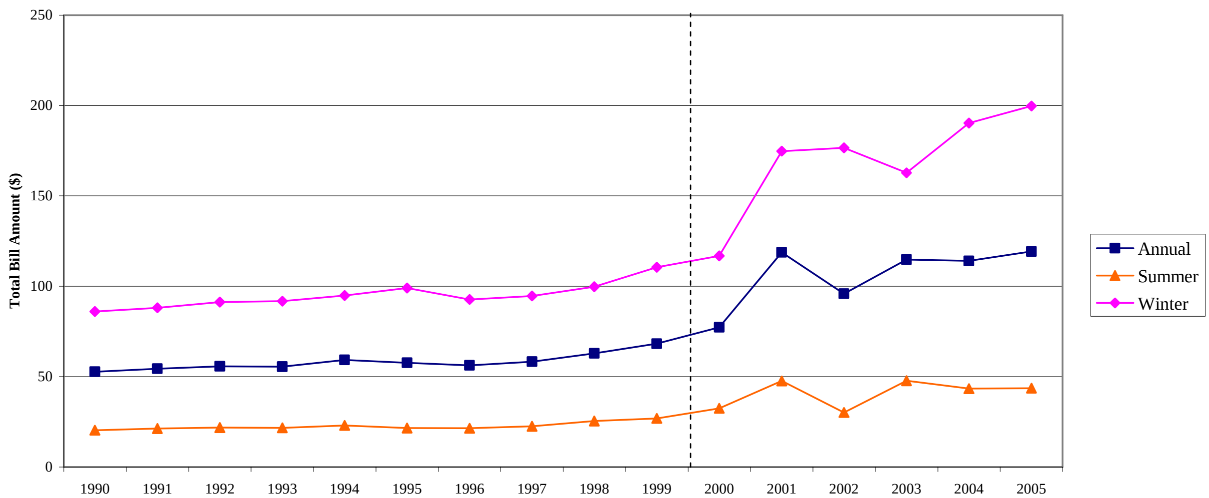
While these changes in the commodity market pre and post-1999 are dramatic, even those averages mask to some extent the market changes experienced in just the last 12 months, as NYMEX forward prices on both a 12 and 36-month basis have risen to the US $8 to $12 per GJ range. This reflects the market's current perception that we have entered a sustained period of high natural gas prices and high price volatility that has not been seen before in North America. Whether or not these changes in the gas commodity market are permanent or temporary is a subject of debate (the market, at least, is forecasting a continuation of the pattern for at least the next three years.) One thing we can be sure of, however, is that there will be continued uncertainty in future prices and increased price volatility.

Q24. How do these changes in the natural gas commodity price environment translate to the Company and its customers?

A24. Ultimately these price level and volatility changes in the wholesale market are reflected in the retail market. To see this, I have plotted the Company's average monthly bill amounts for its Rate Class 1 and Rate Class 6 by season in Figures 4 and 5. Using the Company's residential Rate Class 1 as an example, Figure 4 shows that over the nine years leading up to 1999 the average monthly bill was $58.10 with a standard deviation of $4.54, and that this amount had increased by roughly 29 percent over the period. After 1999 the average residential Rate Class 1 monthly bill was $106.68 (an 84 percent increase) while the standard deviation of those amounts increased to $16.73. As the figure shows, even more dramatic changes are observed in the winter season rates.

Figure 4

Rate Class 1



Rate Class 1 Pre-1999

	Yearly Average	% Change	Standard Deviation
Annual	58.10	29.40	4.54
Summer	22.62	31.97	2.02
Winter	94.86	28.42	6.97

Rate Class 1 Post-1999

	Yearly Average	% Change	Standard Deviation
Annual	106.68	54.22	16.73
Summer	40.83	34.35	7.63
Winter	170.16	71.02	29.14

Notes: Summer rate is calculated using the average of June, July, and August.
Winter rate is calculated using the average of November and December from previous year, January, February, and March from current year.

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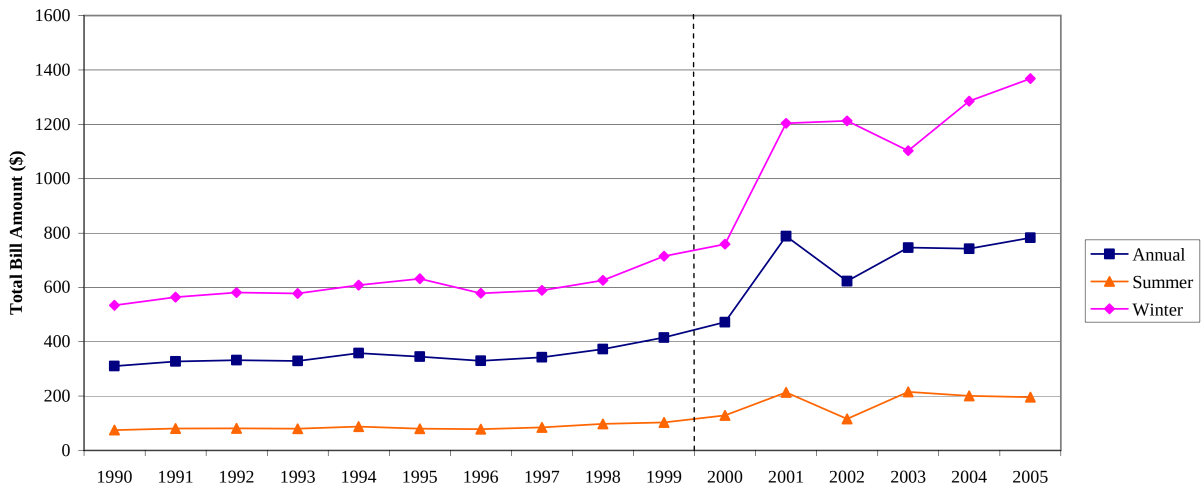
Figure 5

Rate Class 6



Rate Class 6 Pre-1999

	Yearly Average	% Change	Standard Deviation
Annual	346.43	33.77	29.92
Summer	84.94	38.57	9.01
Winter	600.47	33.96	49.61

Rate Class 6 Post-1999

	Yearly Average	% Change	Standard Deviation
Annual	692.45	65.65	123.23
Summer	178.62	51.53	44.06
Winter	1155.38	80.34	213.46

Notes: Summer rate is calculated using the average of June, July, and August.
Winter rate is calculated using the average of November and December from previous year, January, February, and March from current year.

These fundamental changes in the commodity price environment have begun to induce changes in customer use of the Company's network. This can be seen in decreases in the Company's historical and forecast usage per customer.

Q25. What impact has increased commodity price volatility had on the Company's demand forecasts?

A25. Increased commodity price volatility has led to increased uncertainty in the Company's forecast usage per customer. This can be seen by comparing Board-approved average usage per customer to actual average usage per customer in the years 2001 and 2005, two years in which gas commodity prices were particularly high and volatile. Unexpectedly high prices in these two years contributed to decreases in actual usage relative to forecast usage.

Q26. How is the change in the commodity price environment affecting the demand for the Company's services by industrial customers?

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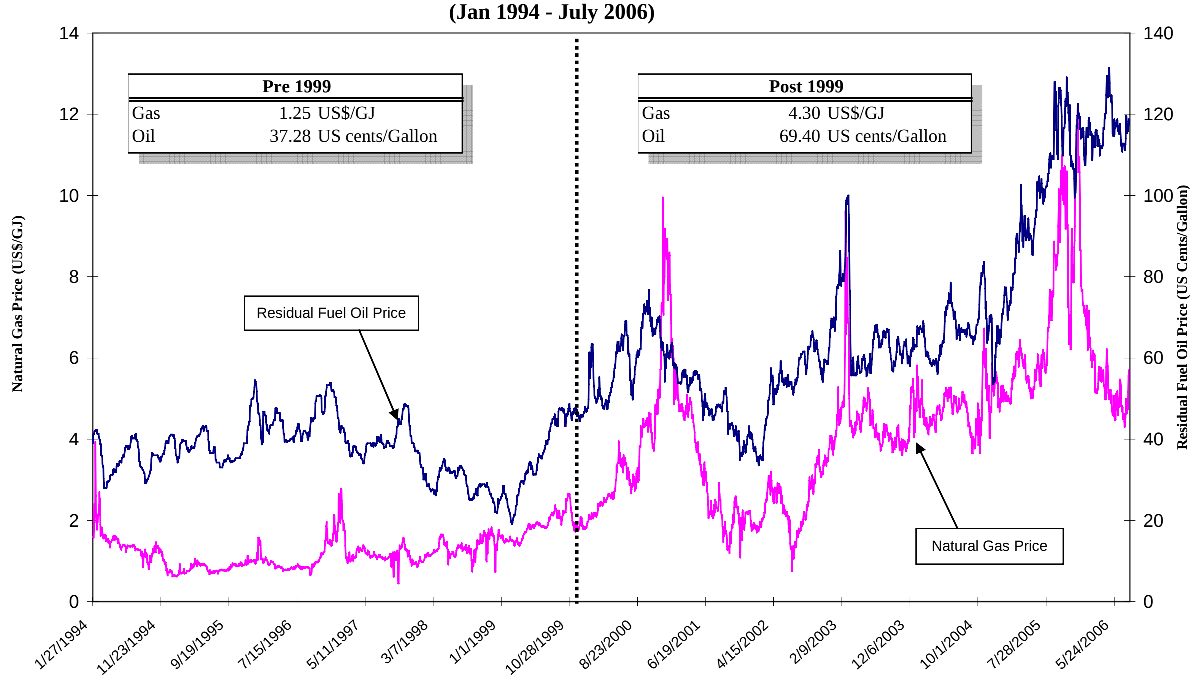
A26. The current commodity price environment contributes to increased uncertainty regarding usage by industrial customers. It makes it more likely that the Company will lose industrial load, either through demand destruction (the closure of industrial facilities) or fuel switching. With respect to fuel switching, the change in the relationship between the price of natural gas and the price of HFO since the period prior to 1999 is significant, as seen in Figure 6.

Figure 6

Nova (AECO) Spot Prices and NY Harbor Residual Fuel Oil Spot Prices
(Jan 1994 - July 2006)



Note: Null prices are omitted to adjust for inactivity.

Sources: Gas Daily and EIA Petroleum Data.

As the figure indicates, in the period prior to 1999 natural gas at wholesale from the WCSB was quite cheap in comparison to HFO purchased at the New York Harbor. Since 1999, while the average price of HFO has increased by about 85 percent relative to the pre-1999 period, the price of natural gas has increased by 245 percent over the same period. Consequently, the price advantage that natural gas had relative to oil for customers with fuel-switching capability has been essentially eliminated.

Q27. What do you conclude regarding the effects of the changed gas commodity environment on the risk associated with the Company's gas distribution business?

A27. Equity investors looking at the Company's gas distribution business will be primarily concerned with uncertainty surrounding the short and long-term utilization of the Company's distribution assets. Since 1993 there has been a fundamental change in the natural gas commodity price environment in which the Company operates. This change has already begun to affect negatively the utilization of the Company's network across its rate classes, and there is substantial future uncertainty in this utilization. This represents a significant change in the Company's business risk.

B. INCREASED POTENTIAL FOR BYPASS OF THE COMPANY'S DISTRIBUTION SYSTEM

Q28. Is the Company currently at risk for potential bypass of its system?

A28. Yes, it is. On January 6, 2006 the Board issued a decision regarding the application of Greenfield Energy Centre Limited Partnership ("GEC") to construct a gas pipeline to serve its 1,005 MW gas-fired generating station in Courtright, Ontario in Union Gas Limited's service territory that would bypass Union.[4] Union also filed an application to serve the GEC power station. In its decision the Board authorized both projects, and essentially is "letting the market decide" which project should be built. The policy reflected in this decision increases the uncertainty associated with both Union's and the Company's exposure to future bypass.

C. UNCERTAINTY IN THE GROWTH OF GAS-FIRED POWER GENERATION FORECASTS

Q29. How has the market to serve gas-fired power generation in Ontario changed since 1993?

A29. Since 1993 there have been fundamental changes in the structure and regulation of the power generation market in Ontario. Most important to the Company's equity investors

4 Ontario Energy Board, Decision and Order, RP-2005-0022 et.al., January 6, 2006.

is the Ontario Government's recent decision to replace coal-fired electricity generation with other technologies on environmental grounds by 2009. The Government has identified new gas-fired power stations as one source that could be relied on. This change in policy has created significant uncertainty as to the extent of new gas-fired power generation demand that may come on line, when, and served by whom. Naturally, this power market uncertainty has a direct effect on uncertainty in the gas market.

Q30. What is the extent of this uncertainty?

A30. The extent of the uncertainty can be judged by examining the range of scenarios that the Board Staff identified last November in its *Natural Gas Electricity Interface Review*.[5] In that study Board Staff created three scenarios based on the IESO 10-Year Outlook and various assumptions about technology/fuel choice for power generation. In particular, the high and low scenarios are determined by the demand forecasts and the amount of nuclear generation that is assumed to replace coal technology. The result is gas use growth by gas-fired generators in 2012 that ranges from 164 PJ/year (0.86 PJ/day on peak) in the low scenario to 320 PJ/year (1.35 PJ/day on peak) in the high scenario.[6]

Board Staff has translated this range of uncertainty into scenarios for required investment in natural gas storage and pipeline infrastructure in Ontario by 2012. The extent of this uncertainty is huge, from $245 million in the low case to $815 million in the high case. There is also uncertainty as to whether this investment will be required of the utilities or other competitors.

Q31. If the market is likely to grow, why is this investment risky?

A31. This investment is risky because there is so much uncertainty in the market, that investors cannot be assured that some of those newly sunk assets will not become stranded or unutilized. While the Board is obviously working hard to assure that there is

5 Ontario Energy Board Staff, Natural Gas Electricity Interface Review, EB-2005-0306, November 21, 2005.
6 *Ibid*., page 13

coordination between the needs of the electricity market and the requirements it places on gas infrastructure, there is risk nonetheless. Board Staff puts it this way in its report:

> A central planning function exists in the electricity market primarily through the IESO and OPA, while no provincial agency exists in the natural gas market. Board staff are not advocating a central planning function in the gas market, but information exchanges could be valuable to stakeholders. This Review is the first step in understanding the implications of new gas-fired power generators for the province's natural gas infrastructure. *However, Board staff realize that there is great uncertainty with respect to future infrastructure requirements, and periodic updates might be required.*[7]

The Staff's report points out that "many stakeholders raised concerns regarding the risks associated with underutilized capacity from overbuilding and/or stranded assets." Board Staff indicated that these issues would be dealt with on a case-by-case basis.[8]

Q32. What do you conclude about the uncertainty of gas-fired power generation demand for the Company's business risk?

A32. While growth in the demand for gas to supply power generation in Ontario is an opportunity for the Company, it is one that creates uncertainty as to the amount, timing, investment requirements, and cost recovery. Moreover, it is an opportunity for the Company that may face substantial competition, as reflected in the bypass application of GEC and the Board's regulatory policy to use that competition to pick the winners. As the Board Staff stated in its report cited above, there is no central planning function for gas infrastructure in Ontario. This set of business risks did not exist at this level of scale or uncertainty in 1993.

D. HEIGHTENED REGULATORY UNCERTAINTY ASSOCIATED WITH THE COMPANY'S DISTRIBUTION BUSINESS

7 *Ibid*., pages 27-28, emphasis added.
8 *Ibid*., page 25.

Q33. You described changes in the Company's market risk due to dramatic changes in commodity prices. Are there any indications that this market risk may well increase in the future in ways that would be of concern to investors in the Company's equity?

A33. Yes. There is substantial uncertainty associated with the future regulation of the Company's gas distribution business, as recognized by the Board in its Natural Gas Forum process. This uncertainty enhances the market risk that the Company faces.

Q34. What is the nature of this future uncertainty?

A34. As part of its Natural Gas Forum process, the Board determined that it will begin a process to establish a firm gas rate regulation framework. The Board has articulated its goals for a rate regulation framework as follows:

> The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.[9]

The Board envisions a series of generic and utility specific proceedings that together will establish a firm framework for gas rate regulation. The Board described this series of proceedings as follows:[10]

- Annual Adjustment Mechanism – "The Board will hold a generic hearing to determine the appropriate base for setting the annual adjustment mechanism. The Board expects that once the generic methodology is determined, its application to each utility may result in different specific adjustments."
- Rebasing – "Each IR plan must begin with a robust set of cost-based rates, based on a thorough and transparent review. The Board's view is that a thorough cost-of-service

9 "Natural Gas Regulation in Ontario: A Renewed Policy Framework," Report on the Ontario Energy Board Natural Gas Forum, page 22.
10 *Ibid*., pages 23-36.

rebasing must occur at the end of each IR's plan's term before a new plan is put in place. Rebasing is an important consumer protection feature. Through robust rebasing, efficiency improvements will be revealed and their benefits passed on to customers through base rates for the next period. The Board will determine the base rates through a hearing for each utility."

- The Term of the Plan - "The Board expects that the term of IR plans will be between three and five years. The Board's view is that three years represents the minimum term that may be expected to give rise to productivity increases, and its preference is for a term of five years. The Board is reluctant to approve a term greater than five years at this time, give the importance of ensuring that productivity gains are passed on to customers in subsequent periods. The term of the plan will be determined in the generic hearing on the annual adjustment mechanism."
- Service Quality Monitoring – "The Board will develop the service quality framework, and will undertake a consultation to finalize the measures, standards and reporting mechanism. The Board expects to use its rule making tools to implement this framework."
- Financial Reporting – "The Board will consult with stakeholders and modify the Gas Reporting and Record Keeping Requirements (RRRs) as necessary to meet the requirements for financial reporting in the new ratemaking framework. While the Board intends to conduct this consultation and modify the RRRs before the development of the first IR plan, it expects that the RRRs may be further refined in the context of specific IR plan development."
- Data Filing Guidelines – "The Board will undertake a review of the gas utility data filing guidelines for rate hearing processes, and then develop a set of draft filing guidelines, which it will distribute for consultation. Wherever possible, the Board will seek to develop consistent guidelines for Union and Enbridge, and will consider issues such as electronic filings."
- The Role of Alternative Dispute Resolution – "The Board is mindful of the concerns stakeholders have expressed and the efforts they have made to propose improvements to the ADR process. The Board will not decide at this time the precise structure of

> the ADR process. The Board has already undertaken a review of the ADR process, and it will consider the submissions made through the Natural Gas Forum before releasing its conclusions in the ADR review. The Board expects that the ADR process will evolve further in the process leading up to the first IR applications."

The resolution of all of these issues by the Board will determine the extent to which the future market risk faced by the Company and its shareholders will increase over and above current market risk. Current uncertainty regarding the ultimate resolution of these issues exposes the Company and its shareholders to an additional regulatory risk.

Q35. What do you conclude with respect to the Company's business risk as it relates to its equity thickness and cost of capital?

A35. Since the last time the Board examined the Company's business risk as it relates to its deemed equity thickness there have been significant changes in the market in which the Company operates. The Company's business risk today is higher than it was in 1993 due to fundamental changes and increased uncertainty in gas and oil commodity markets and the potential for bypass of its distribution facilities. Substantial uncertainty as to the effect of the Ontario Government's new gas-fired electricity generation initiatives on required natural gas infrastructure in the province may place potentially new and large financing requirements on the Company with uncertain outcomes. Finally, investors in the Company's equity will also recognize that there is significant uncertainty as to the regulatory model that will apply to the Company in the future, as reflected in the issues before the Board in its Natural Gas Forum process. For all of these reasons I conclude that an increase in the Company's equity thickness is warranted.

Q36. Does this complete your written evidence?

A36. Yes, it does.

PAUL R. CARPENTER **Principal**

Dr. Carpenter holds a Ph.D. in applied economics and an M.S. in management from the Massachusetts Institute of Technology, and a B.A. in economics from Stanford University. He specializes in the economics of the natural gas, oil and electric utility industries. Dr. Carpenter was a co-founder of Incentives Research, Inc. in 1983. Prior to that he was employed by the NASA/Caltech Jet Propulsion Laboratory and Putnam, Hayes & Bartlett, and he was a post-doctoral fellow at the MIT Center for Energy Policy Research. He is currently a Principal and Vice Chairman of *The Brattle Group*.

AREAS OF EXPERTISE

Dr. Carpenter's areas of expertise include the fields of energy economics, regulation, corporate planning, pricing policy, and antitrust. His recent engagements have involved:

- *Natural Gas and Electric Utility Industries*: consulting and testimony on nearly all of the economic and regulatory issues surrounding the transition of the natural gas and electric power industries from strict regulation to greater competition. These issues have included stranded investments and contracts, design and pricing of unbundled and ancillary services, evaluation of supply, demand and price forecasting models, the competitive effects of pipeline expansions and performance-based ratemaking. He has consulted on the regulatory and competitive structures of the gas and electric power industries in the U.S., Canada, the United Kingdom, continental Europe, Australia and New Zealand.

- *Antitrust*: expert testimony in several of the seminal cases involving the alleged denial of access to regulated facilities; analysis of relevant market and market power issues, business justification defenses, and damages.

- *Regulation*: studies and consultation on alternative ratemaking methodologies for oil and gas pipelines, on "bypass" of regulated facilities before the U.S. Congress; advice and testimony before several state utility commissions and the National Energy Board of Canada on new facility certification policy.

- *Finance*: research on business and financial risks in the regulated industries and testimony on risk, cost of capital, and asset valuation for network industries, airports and seaports in the U.S., Canada., Australia and New Zealand.

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Principal

PROFESSIONAL AFFILIATIONS

International Association of Energy Economists
American Bar Association (Antitrust Section)
American Economic Association

ACADEMIC HONORS AND FELLOWSHIPS

Stewart Fellowship, 1983
MIT Fellowships, 1981, 1982, 1983
Brooks Master's Thesis Prize (Runner-up), MIT, 1978

PUBLICATIONS

"The Advent of U.S. Gas Demand Destruction and Its Likely Consequences for the Pricing of Future European Gas Supplies," (with Carlos Lapuerta and Morten Frisch), 16 March 2005.

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CME, CCC, SEC, VECC INTERROGATORY #10

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

On pages 17 to 22, Concentric discusses EGDI's business risk environment structure and fair return standard.

a) With respect to Figure 2 at page 19, please indicate whether EGDI's operating cash flow minus capital expenditures ("free cash flow") is positive or negative for the period 2012-2016 and whether EGDI would be regarded as a growth firm.

b) What is the purpose of graphing ROE against normalized average use as shown in Figure 3 on page 20.

c) Please produce a copy of the Graham and Harvey article referenced at page 20 and in footnote 23.

RESPONSE

a) Concentric does not have the data to complete the requested analysis. However, EGDI has developed an analysis of historical free cash flows at CME, CCC, SEC, VECC Interrogatory#3 at Exhibit I, Issue E2, Schedule 21.3(h).

b) Concentric graphed ROE against normalized average use in Figure 3 on page 20, to demonstrate that as allowed returns have declined so has average use per customer. Although the AUTUVA and LRAM provide recovery for declining use and conservation, they do not entirely mitigate risk associated with lost revenues due to declining use and provide no protection against variations due to weather. The AUTUVA mechanism compensates the Company for only the weather-normalized variance from forecast average use. The LRAM protects only against forecast DSM activity, so EGDI remains exposed to fluctuations in large volume demand not

Witnesses: J. Coyne
J. Lieberman
Concentric

related to DSM. Lastly, the chart illustrates that in the face of significant reductions in demand the company is also experiencing declining returns.

c) Please see attachment for the Graham and Harvey Study referenced at page 20 and in footnote 23.

Witnesses: J. Coyne
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LESSONS FROM THE FINANCIAL CRISIS

CHAPTER 65

The Equity Risk Premium amid a Global Financial Crisis

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We analyze the history of the equity risk premium from surveys of U.S. chief financial officers (CFOs) conducted every quarter from June 2000 to March 2009. The risk premium is the expected 10-year S&P 500 return relative to a 10-year U.S. Treasury bond yield. The last two surveys were conducted during the darkest parts of a global financial crisis, and our results show that the equity premium sharply increased during the crisis. The survey also provides measures of cross-sectional disagreement about the risk premium, skewness, and a measure of individual uncertainty. The level of disagreement in late 2008 and early 2009 is 64 percent higher than 2007 levels. We also present evidence on the determinants of the long-run risk premium. Our analysis suggests the level of the risk premium closely tracks both market volatility (reflected in the VIX index) as well as credit spreads.

INTRODUCTION

During any financial crises, risk increases. In the current crisis, we observed market volatility skyrocket and credit spreads explode. Presumably, crises are temporary phenomena. How does the existence of a crisis affect long-term risk premiums. While we can directly observe credit spreads and measures like a volatility index (VIX), the equity risk premium is elusive.

We provide a unique perspective on the risk premium by analyzing the results over the past 10 years of our quarterly survey of chief financial officers (CFOs). The survey is currently conducted by Duke University and *CFO* magazine. The survey closed on February 26, 2009, and measures expectations beginning in the second quarter of 2009. In particular, we poll CFOs about their long-term expected return on the S&P 500. Given the current 10-year T-bond yield, we provide estimates of the equity risk premium and show how the premium changes through time. We

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also provide information on the disagreement over the risk premium as well as average confidence intervals.

METHOD

Design

The quarterly survey of CFOs was initiated in the third quarter of 1996.[1] Every quarter, Duke University polls financial officers with a short survey on important topical issues (Graham and Harvey 2009). The usual response rate for the quarterly survey is 5 to 8 percent. Starting in June of 2000, a question on expected stock market returns was added to the survey. Exhibit 65.1 summarizes the results from the risk premium question. While the survey asks for both the 1-year and 10-year expected returns, we focus on the 10-year expected returns herein, as a proxy for the market risk premium.

The executives have the job title of CFO, chief accounting officer, treasurer, assistant treasurer, controller, assistant controller, or vice president (VP), senior VP, or executive VP of finance. Given that the overwhelming majority of survey respondents hold the CFO title, for simplicity we refer to the entire group as CFOs. The survey is currently administered over the Internet.

The Premium During the Recent Crisis

The expected market return questions are a subset of a larger set of questions in the quarterly survey of CFOs. The survey usually contains between 8 and 10 questions. Some of the questions are repeated every quarter, and some change over time, depending on economic conditions. The historical surveys can be accessed at www.cfosurvey.org. During the past nine years, we have collected 11,288 responses to the survey. Panel A of Exhibit 65.1 presents the date that the survey window opened, the number of responses for each survey, and the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk premium. This is confirmed in Exhibit 65.2, which displays the historical risk premiums contained in Exhibit 65.1. The current premium, 4.74 percent, is the highest reading in the history of the survey. The March 2009 survey shows that the expected annual S&P 500 return is 7.49 percent, and the implied risk premium is 4.74 percent (7.49 – 2.75).[2] The expected annual S&P 500 return is roughly the same level as the year before. A major factor in the increase in the premium is the 10-year bond yield falling by more than 100 basis points.

Panel B of Exhibit 65.1 presents some summary statistics that pool all 11,288 responses. The overall average 10-year risk premium return is 3.46 percent.[3] The standard deviation is 2.67 percent.

The cross-sectional standard deviation across the individual CFO forecasts in a quarter is a measure of the disagreement of the participants in each survey. Disagreement has sharply increased during the global financial crisis. The average disagreement in 2007 averaged 2.5 percent. The most recent observation is 4.11 percent—a two-thirds increase and the highest observation on record.

We also report information on the average of the CFOs' assessments of the 1 in 10 chance that the market will exceed or fall below a certain level. In the most recent survey, the worst-case total return is 1.27 percent, which is a record low. The best-case return is 12.40 percent, which is a record high. This reinforces the recent increase in the degree of uncertainty.

With information on the 10 percent tails, we construct a probability distribution for each respondent. We use Davidson and Cooper's (1976) method to recover each respondent's probability distribution:

$$\text{Variance} = ([x(0.90) - x(0.10)]/2.65)^2$$

where $x(0.90)$ and $x(0.10)$ represent the ninetieth and tenth percentiles of the respondent's distribution. Keefer and Bodily (1983) show that this simple approximation is the preferred method of estimating the variance of a probability distribution of random variables, given information about the tenth and ninetieth percentiles. The average of individual volatilities has also sharply increased. The average in 2007 was 3.21 percent and the current reading is 4.23 percent—another new high.

There is also a natural measure of asymmetry in each respondent's response. We look at the difference between each individual's 90 percent tail and the nean forecast and the mean minus the 10 percent tail. Hence, if the respondent's forecast of the excess return is 6 percent and the tails are –8 percent and +11 percent, then the distribution is negatively skewed with a value of –9 percent (= 5 percent – 14 percent). As with the usual measure of skewness, we cube this quantity and standardize by dividing by the cube of the individual standard deviation. In every quarter's survey, there is, on average, negative skewness in the individual forecasts. The average asymmetry became more negative at –0.47 and is currently at a record low level.

Recessions, the Financial Crisis and Risk Premiums

Our survey now spans two recessions: March 2001 to September 2001 and the recession that began in December 2007. Financial theory would suggest that risk premiums should vary with the business cycle. Premiums should be highest during recessions and lowest during recoveries. Previous research has used a variety of methods, including looking at ex post realized returns to investigate whether there is business cycle–like variation in risk premiums.

While we have only 36 observations and this limits our statistical analysis, we do see important differences. The average risk premium over the entire sample is 3.46 percent. During recessions, the risk premium is 3.97 percent and during nonrecessions, the premium falls to 3.37 percent. We also see variation in disagreement. During recessions, the disagreement among participants is 2.84 percent and during nonrecessions only 2.40 percent.

The recession that began in December 2007 is a much worse than normal recession. For example, the recession of 2001 was relatively mild and lasted only three quarters. The current recession is already double the length and includes some of the highest unemployment since World War II. Nevertheless, the risk premium is not really much different during this recession (so far) than during the 2001 recession. Over the past six quarters, the risk premium has averaged 3.88 percent. The variation in the risk premiums is displated in Exhibit 65.2.

Exhibit 65.1 Summary Statistics Based on the Responses from the 36 CFO Outlook Survey from June 2000 to February 2009

A. By quarter

Survey Date	Survey for	Number of Survey Responses	10-year Bond Yield	Average Risk Premium	Median Risk Premium	Disagreement (standard deviation of risk premium estimates)	Average of Individual Standard Deviations	Individuals' Worst 10% Market Return Scenario	Average of Individuals' Best 10% Market Return Scenario	Skewness of Risk Premium Estimates	Average of Individuals' Asymmetry
June 6, 2000	2000Q3	206	6.10	4.35	3.9	2.99				0.81	
September 7, 2000	2000Q4	184	5.70	4.65	4.3	2.70				0.49	
December 4, 2000	2001Q1	239	5.50	4.20	4.5	2.31				0.37	
March 12, 2001	2001Q2	137	4.90	4.46	4.1	2.59				0.38	
June 7, 2001	2001Q3	204	5.40	3.79	3.6	2.43				0.49	
September 10, 2001	2001Q4	198	4.80	3.77	3.2	2.53				−0.11	
December 4, 2001	2002Q1	275	4.70	3.98	3.3	2.34				0.66	
March 11, 2002	2002Q2	234	5.30	2.88	2.7	2.17	3.21	3.66	12.23	0.30	−0.28
June 4, 2002	2002Q3	321	5.00	3.18	3.0	2.59	3.41	3.11	12.15	1.96	−0.39
September 16, 2002	2002Q4	363	3.90	4.00	4.1	2.27	3.36	3.10	12.01	1.03	−0.25
December 2, 2002	2003Q1	283	4.20	3.71	3.8	2.39	3.19	3.38	11.83	1.31	−0.28
March 19, 2003	2003Q2	180	3.70	3.66	3.3	2.12	3.57	1.92	11.40	0.49	−0.60
June 16, 2003	2003Q3	368	3.60	3.89	4.4	2.34	3.74	2.17	12.07	0.89	−0.33
September 18, 2003	2003Q4	165	4.30	3.21	3.7	1.87	2.80	3.34	10.78	−0.02	−0.42
December 10, 2003	2004Q1	217	4.36	3.83	3.6	2.22	3.24	3.35	11.94	0.74	−0.46
March 24, 2004	2004Q2	202	3.70	4.10	4.3	2.06	3.46	2.84	12.00	−0.03	−0.28
June 16, 2004	2004Q3	177	4.75	3.04	3.3	2.28	3.06	3.11	11.20	0.96	−0.39
September 12, 2004	2004Q4	177	4.25	3.24	3.3	2.32	3.13	2.70	10.98	0.64	−0.47
December 5, 2004	2005Q1	291	4.35	3.20	3.2	2.63	3.00	3.16	11.10	2.01	−0.36
February 28, 2005	2005Q2	275	4.28	3.19	3.2	2.47	2.99	3.23	11.16	1.49	−0.32
May 31, 2005	2005Q3	318	4.07	2.98	2.9	2.21	3.17	2.50	10.88	0.50	−0.25
August 29, 2005	2005Q4	325	4.20	2.93	2.8	2.20	3.23	2.26	10.82	0.96	−0.50

November 21, 2005	2006Q1	342	4.52	2.39	2.5	2.14	3.40	2.35	11.38	0.57	−0.23
March 6, 2006	2006Q2	278	4.61	2.57	2.4	2.37	3.43	2.11	11.18	1.11	−0.36
June 1, 2006	2006Q3	500	5.05	2.69	3.0	2.69	3.26	3.10	11.70	2.00	−0.23
September 11, 2006	2006Q4	465	4.79	2.50	2.2	2.47	3.29	2.57	11.28	1.37	−0.32
November 21, 2006	2007Q1	392	4.58	3.21	3.4	2.92	3.31	2.98	11.75	1.93	−0.29
March 1, 2007	2007Q2	388	4.55	3.13	3.5	2.39	3.31	2.79	11.56	1.83	−0.38
June 1, 2007	2007Q3	419	4.90	2.94	3.1	2.12	3.20	3.10	11.58	0.61	−0.38
September 7, 2007	2007Q4	486	4.48	3.35	3.5	2.81	3.08	3.39	11.54	1.80	−0.33
December 1, 2007	2008Q1	465	4.04	3.78	4.0	2.73	3.25	2.99	11.60	1.47	−0.32
March 7, 2008	2008Q2	388	3.61	3.97	4.4	2.97	3.16	3.11	11.50	2.28	−0.29
June 13, 2008	2008Q3	390	4.15	3.12	2.9	2.72	3.28	2.49	11.20	2.02	−0.41
September 5, 2008	2008Q4	439	3.69	3.53	3.3	2.59	3.22	2.37	10.90	1.05	−0.41
November 28, 2008	2009Q1	545	3.10	4.12	3.9	3.10	3.66	1.77	11.47	1.66	−0.36
February 26, 2009	2009Q2	452	2.75	4.74	4.3	4.11	4.23	1.27	12.40	1.82	−0.47
Average of quarters		11,288	4.44	3.51	3.46	2.51	3.30	2.77	11.50	1.05	−0.36
Standard deviation			0.70	0.61	0.61	0.40	0.27	0.56	0.45	0.67	0.09
B. By individual responses											
Survey for											
All dates		11,288		3.46	3.30	2.67	3.48	2.49	11.48	1.49	−0.34

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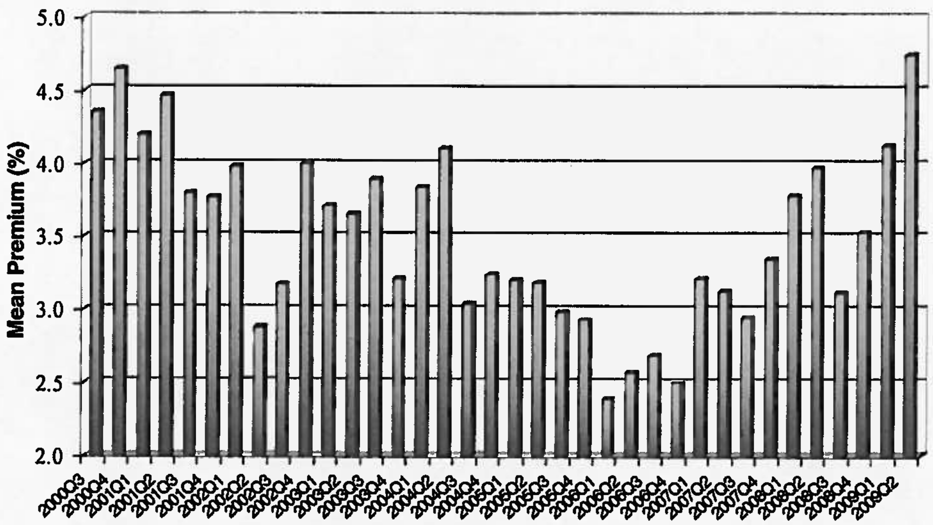

Exhibit 65.2 Ten-Year Forecasted S&P Returns Over and Above the 10-Year Treasury Bond Yield

Explaining Variation in the Risk Premium

While we document the level and a limited time series of the long-run risk premium, statistical inference is complicated by overlapping forecasting horizons. First, we have no way of measuring the accuracy of the risk premiums as forecasts of equity returns. Second, any inference based on regression analysis is confounded by the situation that from one quarter to the next, there are 38 common quarters being forecasted. This naturally induces a moving-average process.

We do, however, try to characterize the time variation in the risk premium without formal statistical tests. Exhibit 65.3 examines the relation between the mean premium and previous one-year returns on the S&P 500.

The evidence suggests that there is a weak negative correlation between past returns and the level of the long-run risk premium. This makes economic sense. When prices are low (after negative returns), expected returns increase.

An alternative to using past returns is to examine a measure of valuation. Exhibit 65.4 examines a scatter of the mean premium versus the price-to-earnings ratio of the S&P 500.

Looking at the data in Exhibit 65.5, it appears that the inference is complicated by a nonlinear relation. At very high levels of valuation, the expected return (the risk premium) was low.

We also examine the real yield on Treasury Inflation-Indexed Notes. The risk premium is like an expected real return on the equity market. It seems reasonable that there could be a correlation between expected real rates of return for stocks and bonds. Exhibit 65.5 examines the 10-year-on-the-run yield on the Treasury Inflation-Indexed Notes.

In this case, there is a weak positive correlation. Lower Treasury Inflation-Protected Securities (TIPS) yields are associated with lower equity risk premiums.

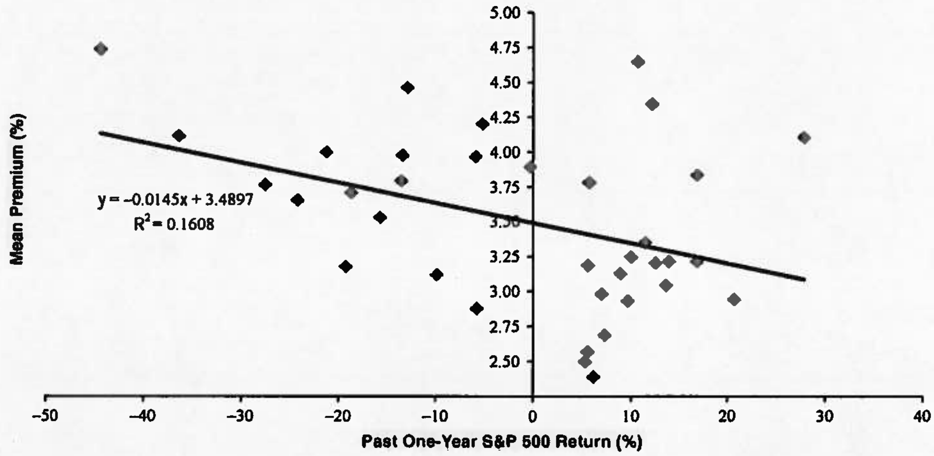

Exhibit 65.3 Equity Risk Premium and Past One-Year Returns on the S&P 500 Index

However, the analysis is only suggestive that the long-run equity premium and real interest rates move together.

Finally, we consider two measures of risk and the risk premium. Exhibit 65.6 shows that over our sample, there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.68. If the closing day of the survey is used, the correlation is roughly the same. Asset pricing theory suggests that there is a positive relation between risk and expected

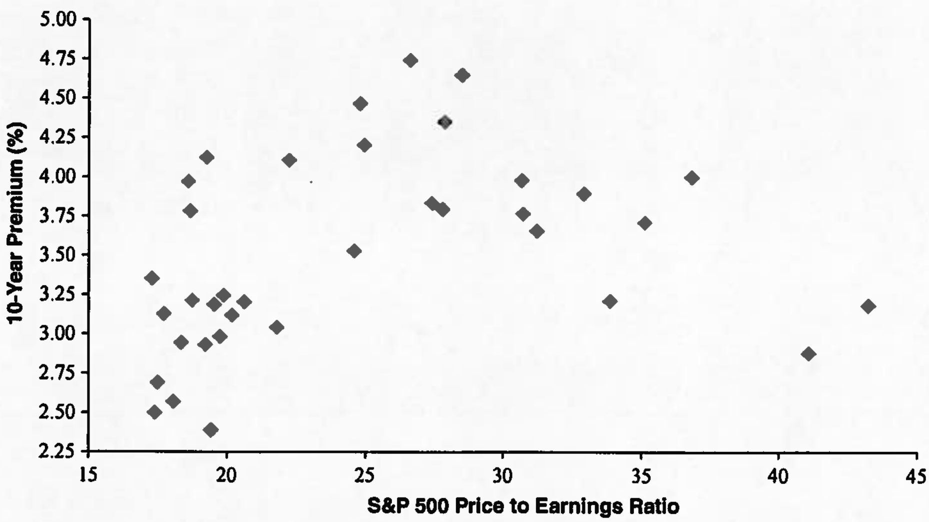

Exhibit 65.4 Equity Risk Premium and the S&P 500 Price-to-Earnings Ratio

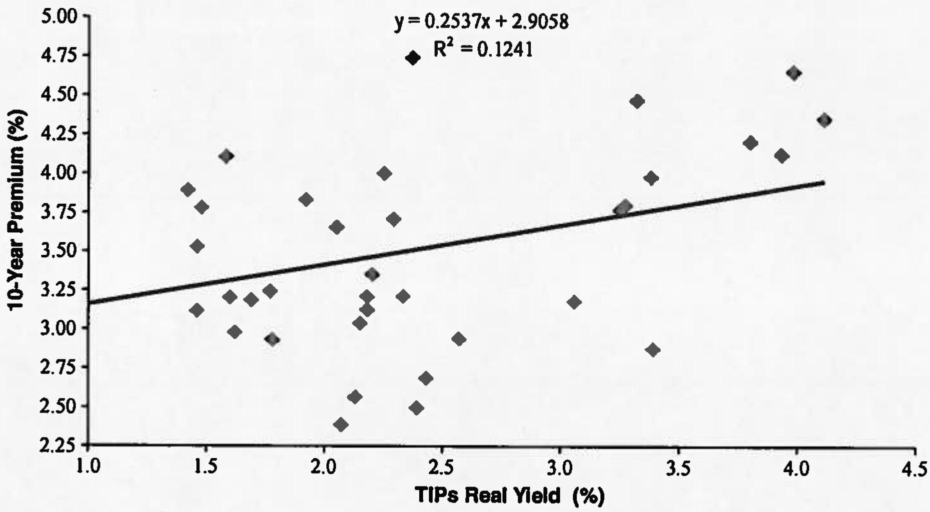

Exhibit 65.5 Equity Risk Premium and the Real Yield on Treasury Inflation Indexed Notes

return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation.

We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa-rated bond yields less the 10-year Treasury bond yield and the risk premium. Exhibit 65.7 shows a highly significant relation between the time-series with a correlation of 0.61.

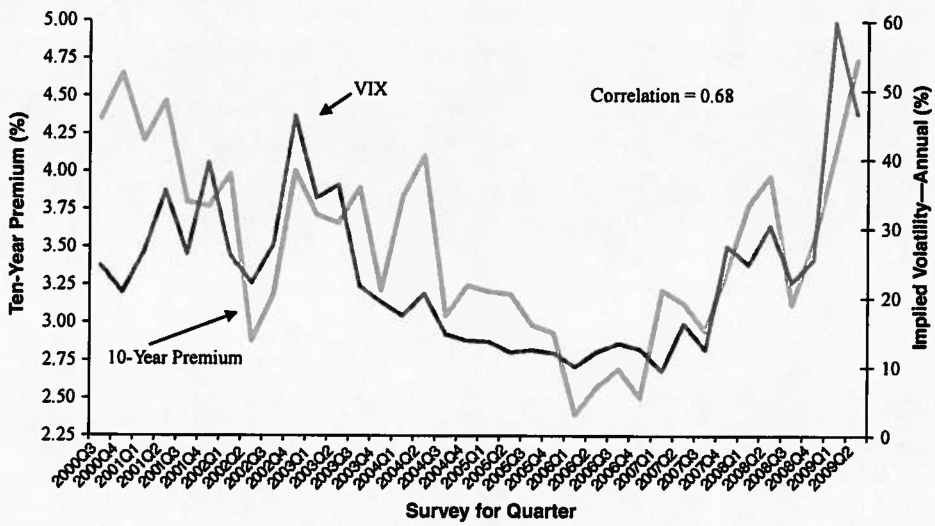

Exhibit 65.6 Equity Risk Premium and the Implied Volatility on the S&P 100 Index Option (VIX)

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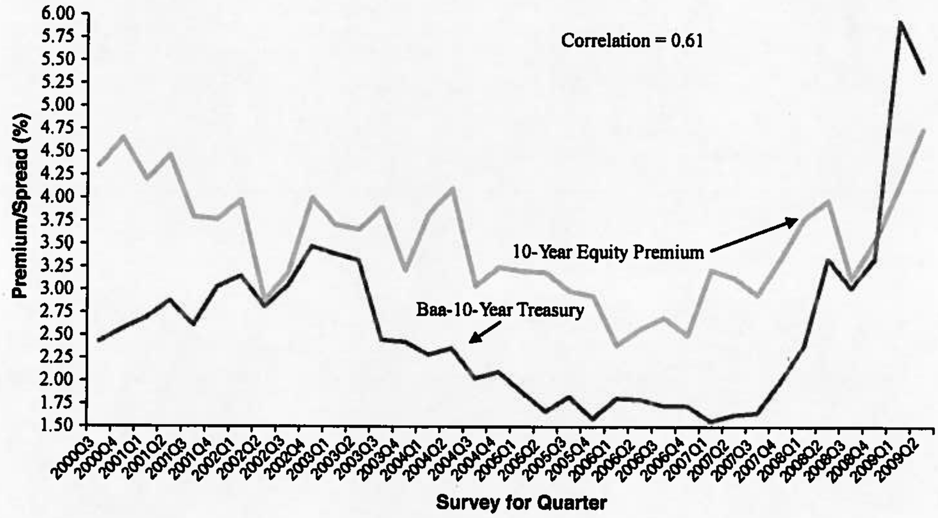

Exhibit 65.7 Equity Risk Premium and Credit Spreads

CONCLUSIONS

During the financial crisis, we study a direct measure of 10-year market returns based on a multiyear survey of chief financial officers. Importantly, we have a measure of expectations. We do not claim it is the true market expectation. Nevertheless, the CFO measure has not been studied before.

While there is relatively little time variation in the risk premium, a number of patterns emerge. We offer evidence that the risk premium is higher during recessions than nonrecessions. Given the current global economic crisis, the risk premium has hit a record high for our nine years of surveys. We also present evidence on disagreement. With higher disagreement, people often have less confidence in their forecasts. We find that disagreement is also higher in recessionary times and the current level of disagreement is at a record level.

While we have 11,288 survey responses over nine years, much of our analysis uses summary statistics for each survey. As such, with only 36 unique quarters of predictions and a variable of interest that has a 10-year horizon, it is impossible to evaluate the accuracy of the market excess return forecasts. There is some weak correlation between past returns, real interest rates and the risk premium. In contrast, there is significant evidence on the relation between two common measures of economic risk and the risk premium. We find that both the implied volatility on the S&P index as well as a commonly used measure of credit spreads are highly correlated with the risk premium.

NOTES

1. The surveys from 1996Q3–2004Q2 were partnered with a well-known national organization of financial executives. The 2004Q3 and 2004Q4 surveys were solely Duke University surveys, which used Duke mailing lists (previous survey respondents who volunteered

their email addresses) and purchased e-mail lists. The surveys from 2005Q1 to present are partnered with *CFO*. The sample includes both the Duke mailing lists and the *CFO* subscribers who meet the criteria for policy-making positions.

2. See, for example, Welch (2000, 2001, 2009), Fraser (2001), Harris and Marston (2001), Pástor and Stambaugh (2001), Fama and French (2002), Goyal and Welch (2003a), Graham and Harvey (2003), and Fernandez (2004, 2006, 2009) for studies of the risk premium.
3. Using the Ibbotson Associates data from January 1926 through March 2009, the arithmetic (geometric) average return on the S&P 500 over and above the 30-day U.S. Treasury bill is 7.20 percent (5.40 percent). Using data from April 1953 to March 2009, the arithmetic (geometric) risk premium is 5.64 percent (4.56 percent). Over the April 1953 to March 2009 period, the arithmetic average return on the S&P 500 over the 10-year U.S. Treasury bond is 4.21 percent. Fama and French (2002) study the risk premium on the S&P 500 from 1872 to 2000 using fundamental data. They argue that the ex ante risk premiums are between 2.55 percent and 4.32 percent for the 1951 to 2000 period. Also see Siegel (1999), Asness (2000), and Jagannathan, McGratten and Scherbina (2001).

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Campbell R. Harvey is a professor of finance at Duke University and a research associate of the National Bureau of Economic Research. He is a graduate of the University of Chicago. Harvey is the editor of the *Journal of Finance*, past president of the Western Finance Association and serves on both the board of directors and the executive committee of the American Finance Association. Harvey has received nine Graham and Dodd Awards, Scrolls, and Roger F. Murray Prizes for excellence in financial writing and has published more than 100 scholarly articles. His 8,000-word hypertextual financial glossary is used by sites such as the *New York Times*, *Forbes*, *Bloomberg*, the *Washington Post*, and *Yahoo.* He has recently released an iPhone app for his glossary. Professor Harvey's blog at http://dukeresearchadvantage.com/author/charvey/ includes an entry from 2005 in which he stated "Many banks are operating like hedge funds, taking advantage of internal (cheap) credit lines. The banks' shareholders have no idea what is going on." He warned of an oncoming "contagious systemic" crisis.

CME, CCC, SEC, VECC INTERROGATORY #11

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

At pages 22 to 27, Concentric discusses credit ratings and provides its hypothetical credit ratings for EGDI. At pages 28 to 30, Concentric compares equity ratios among North American gas distribution utilities.

a) Please identify any Canadian regulator that has "set a goal of the lowest possible investment grade credit rating" in the context of the discussion on page 22.
b) Please provide any precedent decisions where a regulator relied on hypothetical rather than actual credit ratings in determining utility equity ratios.
c) Please provide the full data used to generate the graph on page 27 in machine readable Excel format so that the graph can be replicated.
d) Given the lower common equity ratios of the Canadian utilities shown in Figure 7 on page 31, compared to the US utilities, please explain why all of the Canadian utilities have good investment grade bond ratings.
e) Please confirm that the costs of debt recoverable from EGDI ratepayers should be unaffected by any future S&P downgrades attributable to problems at EGDI's holding company.

RESPONSE

a) Concentric is not aware of any Canadian regulators that have "set a goal of the lowest possible investment grade credit rating". The point of the referenced statement is that with each reduction in credit rating, or with increased financial risk, financial flexibility is further impaired.

Witnesses: J. Coyne
J. Lieberman
Concentric

b) Concentric is not aware of any precedent decisions where a regulator has not considered the potential or "hypothetical" credit rating impact of its equity ratio decisions. However, Concentric is aware of no regulatory decisions that have been based entirely on credit ratings either hypothetical or actual credit ratings.

c) The excel file will be distributed electronically to intervenors following the filing of the interrogatory responses with the Ontario Energy Board.

d) Not all Canadian utilities have good credit ratings. For example, PNG had a below investment grade credit rating in 2000 and 2001, and has been rated at the lowest investment grade since 2003.[1] However, Concentric acknowledges that Canadian utilities do typically enjoy a solid investment grade credit rating. This may be due in part to a large portion of Canadian electric utilities that are government owned and enjoy the benefit of the good credit of the government. Additionally, most Canadian regulatory jurisdictions are deemed by the ratings agencies to be very supportive of credit quality. Both factors weigh heavily into ratings agency decisions.

e) Concentric agrees that the costs of debt recoverable from EGDI ratepayers would not be immediately affected by a future S&P downgrade attributable to problems at EGDI's holding company. However, ratings agencies link the ratings of the holding company and its affiliate companies. If there were a downgrade at the holding company level, depending upon the level of ring fencing in place at the utility level, EGDI ratepayers may share in the effects of the downgrade and EGD may be subject to a down grade itself and as a result, higher debt costs. Though this would not impact the coupon payment on outstanding debt, it may trigger debt covenants and enhanced collateral requirements for existing debt as well as subjecting the utility to higher debt costs and more stringent terms for future financings.

[1] Bloomberg

Witnesses: J. Coyne
J. Lieberman
Concentric

CME, CCC, SEC, VECC INTERROGATORY #12

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

Appendix B discusses regulatory treatment but makes no reference to analyses done by S&P and Moody's of differences between regulatory treatment of utilities in the US and Canada..

a) Is Concentric aware of these analyses of differences?

b) If so, does Concentric agree with these analyses of those differences?

RESPONSE

a) & b) Appendix B of Concentric's Report addresses the regulatory risk profiles of a group of utilities deemed to be comparable in risk to EGDI. Concentric is aware of Reports by S&P and Moody's that discuss their respective assessments of the regulatory environments in Canada and in other countries around the globe.

Standard and Poor's

Most recently S&P has provided a commentary on the global electric utility industry noting the challenges that face each of the countries' regulated electric utilities across the globe. Though their report is specific to electric utilities, much holds true for gas utilities: S&P states:

> *Credit quality trends continued to be somewhat mixed for the rated global utility universe in 2011. Notwithstanding lower or even stagnating economic growth everywhere, utility creditworthiness has been generally stable in several regions, specifically the U.S., Canada,*

Witnesses: J. Coyne
J. Lieberman
Concentric

> *Australia/New Zealand, and in most of Latin America and Asia. However, in Europe and Japan, credit quality momentum remains negative. In Europe, this is attributable to turbulent financial markets and weak economic conditions and the consequent pressures on profitability for many of the competitively exposed vertically integrated power incumbents. In Japan, particularly post-Fukushima, a stalled energy strategy, increasing costs, a sluggish economy, and the downgrade of Japan's sovereign rating continue to pressure credit quality. Across the globe, creditworthiness for entities operating under a predominantly regulated structure remains largely stable, while for those operating under a competitively exposed framework, the challenges have intensified. Common to both though is the need to reinvest heavily in infrastructure, replace assets, and modernize, which could weigh heavily on financial risk profiles if not conservatively financed.*[1]

The headings for the U.S. portion of the Report reads, "U.S. Electric Utilities Maintain Stability Despite Slow Economic Recovery;" and for the Canadian portion reads, "Slow Economy Not Expected To Affect Canadian Utilities' Credit Worthiness," somewhat similar messages. S&P also notes that in regards to the U.S. electric distribution utilities:

> *Creditworthiness in the U.S. electric utility industry has continued a long shift to greater stability. The number of ratings changes has continued to moderate, and upside rating actions have exceeded downgrades in 2011, a departure from the somewhat negative trend in 2010. Since Jan. 1, 2011, Standard & Poor's raised the corporate credit ratings of 27 holding companies and subsidiaries and lowered the rating on ten entities, six of which related to PPL Corp. (BBB/Watch Neg/--). The principal drivers of the upside rating activity were:*
> *· Constructive ratemaking mechanisms and rate orders,*
> *· Decreasing regulatory risk,*

[1] S&P Global Credit Portal, Ratings Direct, Sector Review: How Utilities Around The World Are Coping With Regional Economies (December 21, 2011).

· Managements' commitment to credit quality and a focus on a straightforward regulated utility business model, and
· Improving financial conditions as a result of deleveraging, common stock issuance, and stronger cash flow.

The Report goes on to note that the rating trend for U.S. electric utilities is slightly positive and that the electric utilities are highly rated, especially compared to industrial companies due in large part to their "excellent or strong business risk profiles generally balanced with aggressive financial risk profiles."

In regards to Canadian utilities, S&P notes that despite weak market conditions, evolving environmental regulations, and increased scrutiny by provincial regulators in rate decisions, S&P does not expect overall credit quality to weaken in the near term. They point to regulators' acknowledgement of cash flow strain in creating a supportive regulatory environment and maintaining credit quality. With respect to Ontario, S&P notes:

> *We have observed increased scrutiny by the Ontario Energy Board in rate applications and requirement of the province's local distribution companies to justify cost increases and capital spending in recent rate decisions, as increasing ratepayer costs are emerging as an important concern. So far, this has not resulted in any material disallowances, and we continue to believe regulators will maintain the balance between ensuring prudency of spending and allowing justified returns for regulated utilities.*[2]

On balance we find nothing in the recent S&P report on regulated utilities to indicate that they perceive a regulatory risk divide between the regulatory environments of U.S. and Canadian utilities. The report can be found at Attachment 1

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[2] Ibid.

Witnesses: J. Coyne
J. Lieberman
Concentric

Moody's

At the time of the Consultative Cost of Capital Process in Ontario, Concentric addressed a statement made by Moody's in its August 2009 Global Infrastructure Finance Report on Regulated Electric and Gas Utilities. In the Report, Moody's appeared to be providing its justification of the apparent disparity between its ratings of U.S. utilities versus that of Canadian utilities. Moody's tolerates a much higher degree of leverage and weaker financial profiles from Canadian utilities than it does for U.S. utilities with the same credit rating. In that Report, Moody's stated:

> *In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.*

Concentric submitted a response discussing the Moody's Report in its final comments in the Ontario Consultative Process, in its letter dated October 30, 2009. Concentric's comments with respect to the Moody's Report can be summarized as follows:

- The Moody's Report is provided from a bond holder's perspective and does not attempt to address the very different risks of an equity holder and what is required to achieve a fair and reasonable return on equity.

- With 50 separate regulatory regimes in the U.S., there is greater dispersion of regulatory risk, but by choosing a proxy group of companies that operate in favorable and supportive regulatory environments; this risk can be aligned with the Canadian companies.
- The fact that Moody's feels that regulation generally is more supportive in Canada does not mean that all Canadian jurisdictions have regulation that is more supportive than all U.S. jurisdictions. Only one Canadian utility, Emera is considered in the Moody's report, currently rated Baa2. No Ontario utilities were included in Moody's analysis.
- Because Moody's does not provide a specific basis for its general finding, it is impossible to determine the basis for its vague, general opinion.
- It is possible to form samples of low-risk U.S. utilities that are equivalent to low-risk Canadian utilities.
- Moody's report indicated that among the countries that are considered less risky than the U.S. are Japan, Canada and Australia. However, it should be noted that Australia had just passed a national ROE for its utilities of 11 percent. http://www.aer.gov.au/content/index.phtml/itemId/728192.
- Moody's does not address the Fair Return Standard and evaluates risk only from a bondholder's perspective only. The analysis and concerns of a bond rating agency are primarily with whether certain coverage ratios are met, and whether debt will be repaid. Bond rating agencies are not concerned with whether the common equity is receiving a just and reasonable rate of return or indeed whether Canadian and U.S. equities have comparable risks.

Overall, Concentric believes that though there may be greater ratings and regulatory dispersion in the U.S. by virtue of its 50 separate regulatory jurisdictions and hundreds of investor-owned regulated gas and electric utilities, it is possible to select a group of U.S. gas and electric utilities that operate in highly-supportive regulatory environments and share similar business risk profiles as proxies for Canadian gas and electric utilities. Further, it should be emphasized that the impact of financial leverage on debt holders is much different than on shareholders, and that Moody's is only commenting on the perceived risks associated with debt holdings. The report can be found at Attachment 2

Witnesses: J. Coyne
J. Lieberman
Concentric

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue E2
Schedule 21.12
Attachment 1

STANDARD & POOR'S

Global Credit Portal
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December 21, 2011

Sector Review:
How Utilities Around The World Are Coping With Regional Economies

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Sector Review:

How Utilities Around The World Are Coping With Regional Economies

Credit quality trends continued to be somewhat mixed for the rated global utility universe in 2011. Notwithstanding lower or even stagnating economic growth everywhere, utility creditworthiness has been generally stable in several regions, specifically the U.S., Canada, Australia/New Zealand, and in most of Latin America and Asia. However, in Europe and Japan, credit quality momentum remains negative. In Europe, this is attributable to turbulent financial markets and weak economic conditions and the consequent pressures on profitability for many of the competitively exposed vertically integrated power incumbents. In Japan, particularly post-Fukushima, a stalled energy strategy, increasing costs, a sluggish economy, and the downgrade of Japan's sovereign rating continue to pressure credit quality. Across the globe, creditworthiness for entities operating under a predominantly regulated structure remains largely stable, while for those operating under a competitively exposed framework, the challenges have intensified. Common to both though is the need to reinvest heavily in infrastructure, replace assets, and modernize, which could weigh heavily on financial risk profiles if not conservatively financed.

We also see heightened political and environmental risks for the power industry due to global efforts to reduce carbon and other air emissions. This has, in our view, compounded the more traditional industry exposures to regulatory risks and significant ongoing reinvestment needs. However, Standard & Poor's Ratings Services continues to believe that regulated utilities will be able to recover through rates the ultimate cost of any mandated environmental compliance standards. However, our view could change if developments impel greater compliance spending severe enough to affect the willingness of regulatory bodies to pass on those costs to ratepayers. Meanwhile, many pressured integrated utilities are responding to these challenges by reducing discretionary growth-related investments, increasing cost-containment efforts, completing asset disposals, and proactively prefinancing upcoming maturities. Consequently, a very important dynamic shaping the overall financial condition of the industry will be management decisions and strategies, financial policies, and regulatory decisions.

U.S. Electric Utilities Maintain Stability Despite Slow Economic Recovery

As 2011 draws to a close, about three-quarters of U.S. investor-owned regulated electric companies have stable ratings outlooks and the predominance of ratings remain firmly entrenched in the 'BBB' category, despite a prolonged weak economic recovery. We expect ratings stability to continue based on expectations of responsive regulatory attention to cost recovery for needed capital investments and continued appetite by investors for utility debt and equity offerings.

Standard & Poor's base case outlook for the economy and for the electric utility industry for the remainder of 2011 and 2012 is stable, based on the following:

- Weak economic fundamentals in the U.S., characterized by modest GDP growth, sustained high unemployment levels, a still-weak housing market, and moderate increases in consumer spending;
- Modest growth in electricity consumption, despite the slow economic recovery;
- Generally constructive regulatory decisions; and
- Continued solid capital market access.

Regulated electric utilities have continued to weather the challenging economy of the past few years with little lasting effect on the industry's collective financial risk profile. The essential service that these companies provide and the rate-regulated nature of the business allow them to generate reasonably steady cash flows and to recover the bulk of their costs from ratepayers, despite economic conditions. Nevertheless, in times of exceptional economic hardship, regulators may be very reluctant to approve significantly higher electric base rates for consumers. As a result, we've seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications and large rate increases, which help utilities sustain cash flow measures, earnings power, and, ultimately, credit quality. Hence, we believe that our ratings and outlooks, which we assess based on our view of industry- and company-specific factors, are unlikely to change even if economic conditions worsen in the near term. However, if 2012 produces accelerating economic growth, there could be some very modest improvement in creditworthiness, although probably not enough to revise ratings generally. Stronger employment would help reduce uncollectible accounts, increases in housing starts and the number of households would increase electricity consumption, and regulatory risk could possibly lessen as concerns about the plight of ratepayers abate and rising equity capital costs boost rate increases.

Creditworthiness in the U.S. electric utility industry has continued a long shift to greater stability. The number of ratings changes has continued to moderate, and upside rating actions have exceeded downgrades in 2011, a departure from the somewhat negative trend in 2010. Since Jan. 1, 2011, Standard & Poor's raised the corporate credit ratings of 27 holding companies and subsidiaries and lowered the rating on ten entities, six of which related to PPL Corp. (BBB/Watch Neg/--). The principal drivers of the upside rating activity were:

- Constructive ratemaking mechanisms and rate orders,
- Decreasing regulatory risk,
- Managements' commitment to credit quality and a focus on a straightforward regulated utility business model, and
- Improving financial conditions as a result of deleveraging, common stock issuance, and stronger cash flow.

Notable rating upgrades included those on CenterPoint Energy Inc., Northeast Utilities, and Pinnacle West Capital Corp.

The rating trend for U.S. electric utilities, as measured by outlooks and CreditWatch listings, is slightly positive, with nearly 15% of companies having positive outlooks or positive CreditWatch listings. Nevertheless, the trend is still largely biased toward stable, as about 77% of all U.S. investor-owned electric utilities carried a stable outlook at the end of November 2011. We see virtually no alteration in U.S. regulated electric utilities business risk and financial risk profiles during periods of economic change. As a result, we expect the number of prospective rating changes in the sector to remain moderate in the near-to-intermediate term.

The universe of U.S. electric utilities is relatively highly rated, certainly compared with the average 'BB+' category for U.S. industrial companies. This is a function of the large percentage of firms with excellent or strong business risk profiles, which, however, is generally balanced with aggressive financial risk profiles. As a consequence, almost 70% of the industry carries a 'BBB' category corporate credit rating ('BBB+', 'BBB', and 'BBB-'), about 26% 'A-' and above, and just 4% speculative grade ('BB+' and below).

The U.S. electric utility sector performed well through November 2011, with ongoing favorable access to capital markets compared with most corporate issuers. Reliance on external financing for electric utilities declined in the past 12 months, with the amount of medium- to long-term debt issued during the first 11 months of this year decreasing to about $25 billion from about $34 billion issued during the same period in 2010. We can attribute this to the significant amount of refinancing completed in the prior 12-month period, companies taking advantage of low interest rates with the prefinancing of debt well in advance of maturities and extension of maturities, the winding down of certain construction and environmental compliance programs, and the paring and deferral of discretionary and growth-related construction projects in response to weak economic conditions.

Investor appetite for electric first mortgage bonds remains healthy, with deals continuing to be oversubscribed. Credit fundamentals indicate that most, if not all, electric utilities should continue to have ample access to funding sources and credit. Issuance of common stock to partially fund construction spending is also possible for some firms, and would help to support the capital structure balance. Liquidity is an industry strength and has been improving, and banking syndicates are indicating a willingness to lengthen the terms of credit facilities out as far as five years, in some cases.

To maintain their current creditworthiness in this soft economy, electric utilities will need to have established, and be able to maintain, a firm credit foundation. This will require strong, collaborative, and effective working relationships among management, regulators and, increasingly, legislators and governors, in the planning and execution of strategies. Hence, looking to 2012, the political and regulatory landscape at the state and federal levels will continue to exert the most influence on electric utility credit ratings. Cost increases, construction projects, environmental compliance initiatives, and other public policy directives, together with lackluster electric load growth, will necessitate continued reliance on rate relief by electric utilities. Modest economic growth, better consumer and business confidence, and an improving job market should result in more credit-supportive regulatory outcomes. If the economy contracts, if employment levels weaken, and if consumer sentiment declines, regulatory support by state commissions will become more tenuous. Insufficient responses by utilities to counteract a reduction in regulatory support may drag on the industry, especially if utilities come under cost scrutiny by regulators, which is virtually inevitable, and could lead us to a negative stance on overall U.S. electric utilities' credit quality.

The Environmental Protection Agency has finalized its Cross-State Air Pollution Rule (CSAPR), which requires 27 states to reduce sulfur dioxide and nitrogen oxides emissions beginning in 2012 and again in 2014, and creates four emissions allowance trading programs. The CSAPR is not likely to lead to a shift in credit quality for the regulated electric utility industry. We have incorporated into current ratings the belief that costs associated with mandated environmental compliance standards would be recovered through state regulatory proceedings. However, our view could change if compliance spending becomes onerous enough to affect the willingness of state regulatory bodies to pass those costs on to ratepayers.

With regard to merger and acquisitions, we lowered the corporate credit ratings on DPL Inc. (BBB-/Stable/--) and subsidiary Dayton Power & Light Co. (BBB-/Stable/--) by three notches following the late November acquisition by lower rated AES Corp. (BB-/Stable/--). We also lowered the senior unsecured debt at DPL to 'BB+' from 'BBB+', the preferred stock to 'BB' from 'BBB', and the senior secured debt at DP&L to 'BBB+' from 'A'. The lower ratings are attributable to the substantial amount of acquisition-related debt incurred at DPL. Moreover, we believe that the combination with an entity that has significantly weaker business risk and financial risk profiles, as well as the ample leverage employed, demonstrates a lack of commitment to credit quality by DPL's management.

Several merger and acquisition transactions are pending various approvals. These combinations include:

- Exelon Corp. (BBB/Stable/A-2) and Constellation Energy Group Inc. (BBB-/Watch Pos/A-3),
- Northeast Utilities (BBB+/Watch Pos/--) and NSTAR (A+/Watch Neg/A-1), Duke Energy Corp. (A-/Stable/A-2) and Progress Energy Inc. (BBB+/Watch Pos/A-2), and
- Gaz Metro Limited Partnership's (A-/Stable/--) and Central Vermont Public Service Corp. (not rated).

Creditworthiness appears to be a factor in the recent flurry of mergers rather than an exclusive focus on shareholder value. Managements are more accepting of lower synergies and cost-saving assumptions, and acquisition premiums have declined. While the deals have not always been beneficial for all bondholders, the new merger model will produce larger, financially healthier and lower-risk regional utilities that are better able to manage regulatory risk, undertake large construction programs, and expand with minimal additional risk. While we continue to judge the credit implications of a merger transaction in the context of ongoing business strategies and financing plans, from our perspective a more efficient industry, with more concentration on relatively low-risk regulated operations could lead to improving creditworthiness for the sector.

Slow Economy Not Expected To Affect Canadian Utilities' Creditworthiness

Canadian utilities companies have been active in acquisitions and project developments recently, and this has affected credit quality for some of them. Despite weak market conditions, evolving environmental regulations, and increased scrutiny by provincial regulators in rate decisions, Standard & Poor's doesn't expect overall credit quality to weaken in the near-to-medium term. Exceptions could include companies that add substantive assets with higher cash flow variability or adopt more aggressive financial leverage policies to support growth aspirations. We maintain our view that higher-than-average regulated asset growth and utility financing and refinancing risk are manageable as utilities continue to enjoy good access to capital markets. Rate decisions from provincial regulators have remained generally supportive to the regulated utilities and pipelines including recognition of cash flow strain during large capital spending build-out in revenue determinations. We have observed increased scrutiny by the Ontario Energy Board in rate applications and requirement of the province's local distribution companies to justify cost increases and capital spending in recent rate decisions, as increasing ratepayer costs are emerging as an important concern. So far, this has not resulted in any material disallowances, and we continue to believe regulators will maintain the balance between ensuring prudency of spending and allowing justified returns for regulated utilities.

There have been few changes in environmental-related regulations, although we expect the federal government to become more proactive in setting standards and regulations. The federal government has announced plans to close coal plants in existence before July 1, 2015, that reach 45 years of age or whose power purchase agreement expires, whichever is later unless they incorporate carbon-capture-and-storage or other feasible technologies to reduce greenhouse gas emissions to levels similar to that of a natural gas plant. They also plan to prohibit construction of new coal-fired power plants after July 1, 2015 unless they are able to control their emissions to levels typical of natural-gas plants.

If implemented, these requirements could, in our view, have two different medium-term effects on incumbent generators, particularly in Alberta, where coal-fueled plants make up more of the province's total generation capacity than it does elsewhere. On one hand, operators of aging coal-fired plants could have to close plants reaching the age limits and therefore face reduced generation volume, possible asset write-offs, and higher asset-retirement costs. On the other hand, this could reduce electricity generation capacity and supply and push electricity prices up, unless new facilities take their place quickly. The higher electricity prices could in turn benefit incumbent operators who operate noncoal or newer coal facilities. We will assess the asset mix of each rated generation company and its strategy in response to these requirements as they develop and changes in environmental regulations to determine the impacts, if any, to credit. Ontario is nearing the end of a 10-year period (2004-2014) of phasing out its coal plants, all of which are government-owned. Its coal capacity is gradually being replaced with refurbished nuclear plants and new gas-fired and renewable facilities, as well as conservation efforts.

Canadian economic growth stalled in second-quarter 2011, mostly due to worsening exports for Canadian companies. Although exporting recovered in the third quarter and GDP growth turned positive again, Standard & Poor's expects deteriorating global growth, lower commodity prices and the strong Canadian dollar to continue weighing on the country's economic performance. Slower momentum in domestic spending could also undercut GDP growth as businesses conserve capital and rethink their spending plans, awaiting greater certainty around the economic outlook. With these assumptions, we think it will take longer for excess slack in the economy to disappear, so Canadian workers could be facing a period of diminishing job opportunities. As such, we're assuming Canada's unemployment rate (7.4%) could increase again (likely through mid-2012), after declining through most of 2010 and in the first half of 2011. Against this backdrop, slowing labor income growth could constrain consumer spending as households focus on paying down the increased debt burdens they've accumulated. So we think it will take longer for GDP growth to move back up to rates in the 3.2% area that are typical for Canada's economy during expansionary periods. We've lowered our forecast for GDP growth to 2.3% in 2011 (versus our previous forecast of 2.8% for 2011), and in 2012 we now expect to see growth of 2.1% for Canada (compared with 3% previously). However, we think recessionary risks will remain relatively low for Canada so we do not expect subpar GDP growth to have any meaningful negative effect on regulated utilities in the next two years.

European Utilities' Profitability Is Challenged

Credit trends for the leading European utilities rated by Standard & Poor's remain largely negative overall. Of the top-25 European utilities, for example, 10 have negative outlooks or are on CreditWatch with negative implications. This reflects significant pressure on profitability for many of the competitively exposed vertically integrated power incumbents, an aging generation asset base with significant reinvestment needs, rising political risks, sovereign stress in the eurozone, and higher environmental costs. In addition, turmoil in the financial markets heightens financial risks and, in our view, Europe's economic outlook once again appears increasingly somber. We now expect a mild recession in first-half 2012 in the eurozone, ahead of a modest pick-up in the second part of the year. We anticipate eurozone real GDP growth to average 0.4% next year, which is likely to lead to a fall in energy demand in many European countries.

However, underlying credit quality for regulated utilities, electricity and gas networks in particular, remain relatively solid. Ratings for electricity and gas transmission system operators in the peripheral eurozone countries are largely at risk of being lowered, mainly due to sovereign-related stress.

We believe the larger European power and gas utilities will continue to focus extensively on efficiency enhancements and cost control to relieve some of the immediate pressure on profitability from challenging market conditions. In addition, reductions in capital spending and an acceleration of disposal programs are likely to lead utilities to make efforts to deleverage and to enhance financial flexibility. We are particularly concerned with any possible disruption of financial markets due to unforeseen exogenous shocks, as European utilities have significant amounts of debt falling due in the coming years. We believe utilities based in Greece, Italy, Ireland, Portugal, and Spain to be particularly exposed, as access to long-term funding could be increasingly challenging and will undoubtedly come at a higher cost.

Latin American Utilities Are Expanding Capacity And Infrastructure

Latin American electric utilities fared relatively well in the 2008 economic crisis, supported by its large and dynamic domestic market. This resilience might be tested again if the global economy enters another recession. Standard & Poor's has revised its growth prospects for Latin America, reducing expected real GDP growth to 4.2% in 2011 and 3.8% in 2012 (previous forecast of 4.5% and 4.2%, respectively). However, we expect electricity demand to continue growing above GDP. Consequently, companies are carrying out sizable capital expenditures to not only expand capacity (Colombia, Chile, and Brazil) and diversify energy generation sources (Brazil, Mexico, and Dominican Republic), but also to improve infrastructure (Brazil, Panamá, and Guatemala).

The local capital markets have been very active in Brazil, Chile, Mexico, Colombia, and Panamá, allowing companies to obtain funding mainly in local currency in line with their revenues, thus reducing currency mismatch risks. Also, the companies benefit from long-term and low-cost funding from national development banks and multilateral agents, such as Brazilian National Development Bank, International Finance Corp., and Inter-American Development Bank, especially for the financing of new generation and transmission assets.

Standard & Poor's views Latin American electric utilities as generally well positioned to continue supporting local economies' growth due to the sizable investments under way to improve infrastructure and expand energy supply capacity to serve new consumers in the local markets, especially as a result of social programs.

During 2011, we have raised some ratings of Brazilian electric utilities, reflecting our view of a stable regulatory framework and positive demand trends, combined with generally stronger cash generation and prudent liability management. Most of the upgrades resulted from improved financial risk profiles because the companies benefited from favorable credit market conditions to refinance existing debt with lower funding costs and longer tenors, reducing refinancing risks for the next few quarters.

In the first 11 months of 2011, we've rated debt issuances from Brazilian electric utilities of about Brazilian real (R$) 6.3 billion (about $3.7 billion), in both the local and international markets, with average tenors of six years. Some companies also increased cash position for acquisition opportunities. During 2011, merger and acquisition activity has been quite active with announced transactions of around R$7 billion, from Companhia Energetica de Minas Gerais S.A. (Cemig); CPFL Energia S.A., and Spanish group Iberdrola S.A., with no impact on the existing ratings.

Uncertainties regarding the third tariff revision cycle for distribution companies in Brazil have reduced, with a new methodology almost concluded. The current ratings already reflect our base case scenarios that assume a potential reduction of 20% to 25% in profitability of the rated companies after the tariff reset. Another important topic relates to the expiration of several generation and transmission concession contracts (nearly 20% of Brazil's installed capacity and 50% of transmission lines), from 2015 to 2017, that would revert to the government for new auctions. We believe this matter will be resolved soon, because it's critical for the functioning of the electric system in Brazil--otherwise generators and distributors will not be able to sign long-term energy contracts, which would probably pressure energy prices.

Our ratings on Argentinean electric utilities continue to reflect our view of high regulatory risk, and the continued deterioration in the companies' cash flow generation, as tariffs do not reflect the increases in operating costs. In addition, there is a significant discretion in the political decision-making process that makes it very difficult to forecast future repayment performance and genuine investment plans.

In Chile, companies should continue benefiting from economic growth prospects, boosting power demand. Despite weaker financial performance at some companies due to the prolonged drought in the central and southern regions, all the ratings on our rated utilities remain unchanged in 2011.

In Mexico, the Comision Federal De Eletricidad (CFE) is consolidating its critical role as the only provider of electricity in Mexico and the sole entity responsible for planning and operating Mexico's electric system. In mid-2011, CFE tapped the international market for the first time in over a decade with a US$1 billion issue as part of it diversification and growth strategy into alternative generation sources and national grid expansion.

In Colombia, we view Interconexión Eléctrica S.A., ISAGEN S.A., Empresa de Energía de Bogota S.A., and Transportadora de Gas Internacional as well positioned for a soaring period to come, enhanced by a developed and stable regulatory environment in the country. The successful diversification of the companies' core operations into several countries in the region, such as Brazil, Chile, Peru, and Panama, which now have investment-grade sovereign ratings, and the diversification of their businesses into nonenergy-related operations is consistent with becoming operating holding groups. We expect these companies to continue posting strong cash-flow metrics and maintain prudent debt-management policies as they consolidate their business strategies and geographical outreach.

Overall, we still expect that medium-term growth for the Latin America electric sector will continue getting support from the utilities' domestic markets to face global turbulence. Despite lower economic growth prospects, the region should keep positive market dynamics. We also believe that improved access to financing in local capital markets as well as in local and foreign bank markets will generally enhance financial flexibility for the next few years.

Australian Utilities Face Regulatory Challenges

In Australia, legislation introducing the federal government's carbon abatement scheme passed, and will be introduced on July 1, 2012. The scheme could complicate the re-financing of a number of coal-fired generators with debt that falls due about the time or shortly after the scheme begins. In other Australian regulatory developments, a series of proposed rule changes and multiple reviews of the energy sector are the next tests for Australian utilities' credit quality. How the rated entities respond to these evolving changes will be critical in determining the ultimate impact on the sector's credit quality, given that the regulatory framework is an important component of the regulated utilities' businesses. Most rated utilities are on a stable footing, with only three companies on negative rating outlooks as of Nov. 21, 2011.

In New Zealand, the re-election of the National Party government last November is expected to result in the sale of the three state-owned integrated generator-retailers. While the timing is yet to be determined, it is expected that this process will begin sometime in 2012.

Asian Utilities' Credit Quality Should Retain Stability

The credit quality of electric utilities that Standard & Poor's rates in Asia is likely to remain broadly stable in the next 12 months. These companies benefit from favorable industry dynamics and demographic trends that point to increasing demand for utility services. Economic growth in the region is faster than the world average, and domestic populations are large with low electricity consumption and urbanization is increasing. Regulatory frameworks broadly support this sector, and in some markets, governments provide direct subsidies and other support.

Some of the notable rating actions this year include the multiple downgrades of Tokyo Electric Power Co. Inc. (TEPCO) to B+/Watch Dev/B, from AA-/Stable/A-1+ prior to the March 11 natural disaster, and the downgrade of several Japanese electric utilities to A+/Negative/A- from AA-/Negative/A-1+ to reflect the uncertain environment for electric utilities in Japan (see separate section on Japan below).

Economic growth across the region is being revised downwards as financial turbulence in advanced Western economies is spilling over into the region. Demand for electricity in the region, particularly from the industrial sector, is likely to slow down if the global economy enters another recession. In our view, the economic decline alone is unlikely to result in downgrades of utility companies. Since electricity demand is not particularly elastic, declines in usage may not be as large as the overall economic contraction. This is particularly true if a major portion of a utility's customer base is residential, where usage is less affected by economic cycles. The more pressing issue is the ability of utilities to adapt to the changing economic and financial environment. Some economies in the region, such as Singapore, Thailand, and the Philippines, rely heavily on export-driven income, and a global slowdown may affect economic growth. For countries such as India, China, and Indonesia that have sizable domestic economies, the impact of another global slowdown on their domestic utilities may not be that much.

Inflation across the region remains high, and has been inching up in most economies throughout the year. Inflation is being further exacerbated by rising fuel costs for electric power plants, contributed largely by the natural disasters in the region this year, including earthquakes in New Zealand, flooding in Australia and Southeast Asia, and the twin disasters in Japan. The approach of governments across the region to address rising fuel costs has been mixed across the region depending on:

- The tariff frameworks in their respective countries,
- The availability of fuel sources domestically, and
- The extent of government subsidies.

Governments and regulators are reluctant to raise tariffs to protect utilities even as fuel costs rise because such hikes could fuel inflation. Without government subsidies or support, delays in tariff increases affect utilities' profitability and cash flows.

Competition for fuel is on the rise following the natural disasters, as well as market-specific factors such as the coal shortage in large, power-hungry economies like India's. To secure fuel, Japanese firms are investing heavily in several liquefied natural gas terminal projects in Australia, while some of the Southeast Asian nations are stepping up oil and gas exploration in the region. Coal shortages in India, which has the third-largest coal reserves in the region where the top three dominate by a wide margin, is also driving up coal costs. Coal India Ltd. (not rated), the country's leading state-owned producer, has not been able to mine coal at a rate that could keep pace with demand. This has led to Indian electricity companies getting coal from coal-rich countries such as Indonesia and Australia.

Vertical integration through acquisition of stakes in operations of companies that produce primary fuel has helped some companies address fuel security. For example, Indian utilities, such as Tata Power Co. Ltd. (BB-/Positive/--), have been acquiring coal mines in Indonesia and Australia, while many Chinese power companies have ventured into upstream coal mine acquisitions to hedge fuel cost risk. Sizable investments may at times pressure the gearing of companies, especially if gearing is already high.

Although the ratings of our rated electric utilities in the region are broadly stable, we are focusing heavily on three key markets over the next 12 months. The first is Japan, where problems at the Fukushima nuclear plant following the March 11 earthquake and tsunami have made the country's energy policy uncertain. We are watching closely actions by the Japanese government for compensation plans to be introduced for TEPCO and more broadly its effect on other Japanese electric utilities. The second market is Korea, where we think the stand-alone credit profile of Korean electric utilities will continue to be pressured due to the industry's inability to pass on higher fuel costs for electricity to consumers due to an inefficient tariff structure, and reluctance by the government to increase tariffs due to high inflation levels in the country. The third market is China, where the aggressive expansionary plans and desire to secure fuel sources of Chinese electric utilities may pressure balance sheets and credit metrics.

More generally in the region, we are monitoring how electric utilities manage their refinancing and liquidity needs, plus their headroom against financial policies and debt covenants. We also continue to pay close attention to shareholder behavior and support, as well as integration and construction risks associated with large capital investments and merger and acquisition activity, both of which we expect to increase across the region.

Japanese Utilities Are Still Dealing With March 2011 Disaster

Post-Fukushima, a stalled energy strategy and increasing costs continue to put downward pressure on the Japanese utility sector. Standard & Poor's continued to revise downward credit trends for the utilities through this year, mainly due to:

- Downward revision of Japan's sovereign rating and sluggish domestic economy,
- Significantly increasing costs to replace nuclear power and the capital spending burden to strengthen safety measures following TEPCO's Fukushima No.1 nuclear plant disaster, and
- Increasing uncertainty about government energy policy.

The outlook on all seven of the rated Japanese utility companies is negative. The ongoing Fukushima nuclear disaster has pushed Japan's energy policy to a crossroads. With public sentiment shifting away from nuclear energy, which had been at the forefront of Japan's energy plan for the next decade and given problems with the alternatives, it is difficult to tell what direction a restructured national energy strategy will take. A sharp rise in fuel costs for thermal power and ongoing political uncertainty further complicate how best to provide this essential service.

Until the government's commitment to support TEPCO is confirmed and the government finalizes its new energy policy, the downward trend for the sector should last in our views. Although the central government, in November 2011, approved financial aid to TEPCO, the plan to restructure the company remains unclear. The government's review and approval of the plan is expected to come around next March. We think prolonged uncertainty over the utility sector may lead to higher long-term funding costs in the future.

Rating Methodology

Moody's Global
Infrastructure Finance

August 2009

Regulated Electric and Gas Utilities

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Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Moody's Investors Service

Regulated Electric and Gas Utilities

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

About the Rated Universe

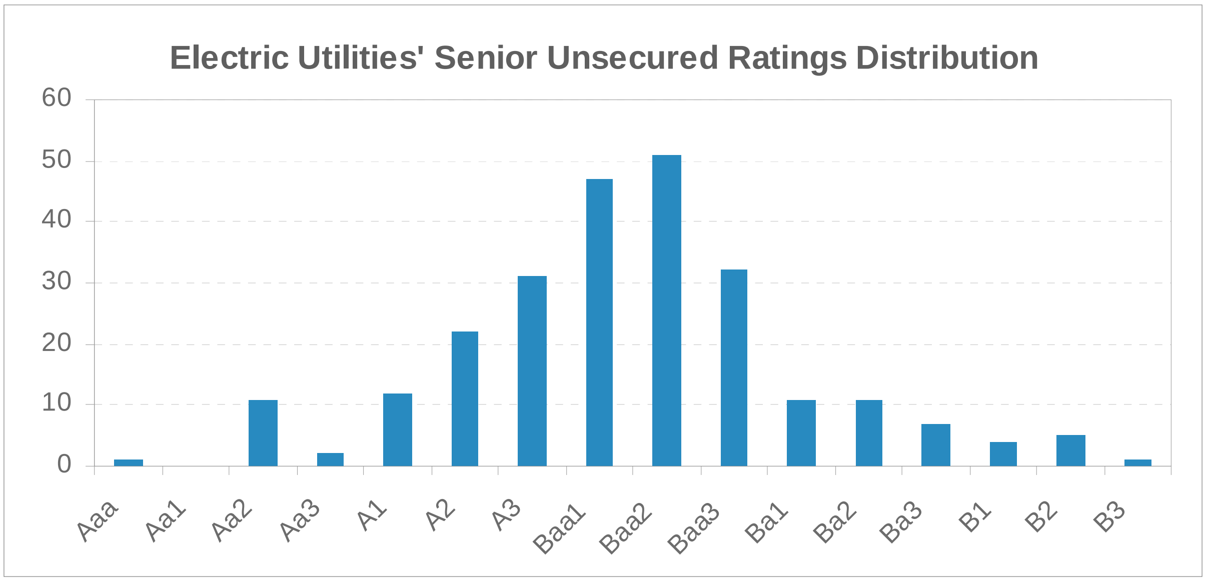
The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility

Regulated Electric and Gas Utilities

businesses[1]. In addition, this methodology includes both holding companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

[1] These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

[2] The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC – Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	**100%**		**100%**

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating	
Indicated Rating	**Aggregate Weighted Factor Score**
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

[3] For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

Rating Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

Unlike Factor 1, which considers the general regulatory framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

More typically, however, and as is characteristic of most utilities in the U.S., the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost recovery or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score of A for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa rating for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with several businesses with large market shares are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the “Sustainable Profitability” and “Regulatory Support” assessments in the previous LDC rating methodology. While LDCs’ authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

Factor 2 – Ability to Recover Costs and Earn Returns (25%)

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies’ cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, the key criterion we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, most of the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation **0% weight for issuers that lack generation*

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

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Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

Measurement Criteria

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

CFO pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial and can affect the ability of a utility to cover its debt obligations. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a utility to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% – 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP – Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation   **0% weight for issuers that lack generation*

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest / Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC / Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends / Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt / Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt / RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	Aa	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

Exhibit 36 Work Papers

Regulated Electric and Gas Utilities

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	Aa	A	A

Positive Outlier

Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework		
Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns		
Factor Weight		**25%**
	Current Rating/BCA	**Rate Adjustment and Cost Recovery Mechanisms**
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification

Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	Aa
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Sub-Factor Weights			10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-WC / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa*
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba*
Eesti Energia AS	A1/[8]	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	Aa	A	A

*Debt/RAV

Positive Outlier	
Negative Outlier	

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

Regulated Electric and Gas Utilities

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, constrained capital market conditions could severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The degree of notching (or rating differential) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody's treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody's treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility's balance sheet. In looking at cash flow coverages, Moody's analysis focuses on ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility's flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover debt service and are made irrespective of whether the utility requires the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

[4] When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.

- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.
- Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.
- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]
- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.
- Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

5 See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
6 SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be the cost of capital of the utility.
- Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total debt obligations.
- Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Moody's Investors Service

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Ref: Ex. E2 /Tab 1/ Sch 1 / para 4

Concentric has prepared an assessment of the 9.42% ROE rate for 2012. Is Enbridge planning to file evidence justifying the use of the ROE proposed for 2013?

RESPONSE

The intent of the Concentric analysis on ROE (Exhibit E2, Tab 2, Schedule 1, pages 9 to 11) was to provide the Board with evidence that the current formula output produces a result that is reasonable. The only standard for testing the reasonableness of the result was the most up to date formula output (9.42% at the time) against then current market data. That evidence showed that using a reasonable proxy group results in a Fair Return of 10.62% on 42% equity. Adjusting the results of the US proxy group downward by 74 bps to account for the prevailing difference in the risk free rates between the US and Canada yielded a Canadian ROE estimate of 9.88% at 42% equity. Concentric concluded, "This adjusted result is aligned with the current ROE formula result of 9.42 percent and supports EGDI's request for an increase in its equity thickness to 42 percent."

EGD's position is that the formula continues to produce a reasonable result. As a result, EGD's aim is to satisfy the Board that it is reasonable to expect that the new ROE formula output, in conjunction with a 42% equity ratio, will meet the Fair Return Standard.

EGD is not planning to file further evidence justifying the use of the ROE proposed for 2013. EGD is proposing to apply the new ROE formula output for 2013 rates, when the data to calculate it is available.

Witnesses: R. Fischer
M. Lister
D. Yaworski

BOARD STAFF INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Ref: Ex. E2 /Tab 1/ Sch 2 / para 15

Enbridge refers to “industrial demand destruction” causing total volumes to decline. Please provide total annual system throughput for the years 2000 to 2013. Please include annual actual customer meters.

RESPONSE

The table below presents total annual system throughput for the years 2000 to 2013, broken down into general service, contract market, and total volumes. Also included are actual customer meters and degree day information. In addition, the graph below illustrates the change in contract market volumes.

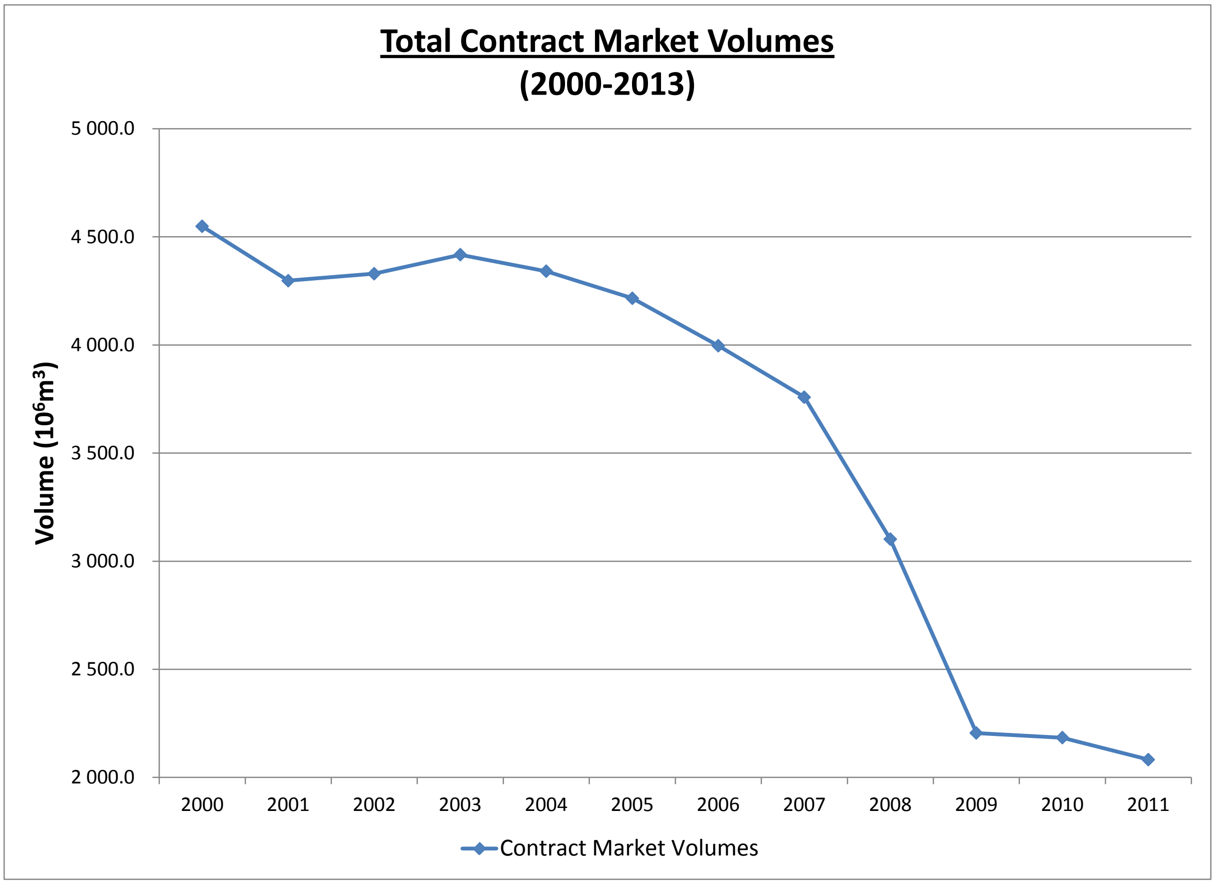
Witnesses: R. Fischer
M. Lister
D. Yaworski

Customer Meters & Volumes
2000-2011 Actual

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Item No.		Fiscal 2000	Fiscal 2001	Fiscal 2002	Fiscal 2003	Fiscal 2004	Fiscal 2005	Calendar 2006
1.	Total Customers (Average)	1 464 738	1 519 039	1 566 710	1 622 016	1 676 380	1 724 716	1 782 813
2.1	Total General Service (10^6m^3)	7 020.1	7 440.9	6 945.2	8 228.9	7 916.3	7 950.4	7 490.5
2.2	Total Contract (10^6m^3)	4 548.5	4 297.1	4 329.3	4 417.3	4 340.5	4 215.6	3 996.4
2.	Total Volumes (10^6m^3)	11 568.6	11 738.0	11 274.5	12 646.2	12 256.8	12 166.0	11 486.9
3.	Degree Days	3 688	3 533	3 632	3 976	3 668	3 784	3 403

		Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Item No.		Calendar 2007	Calendar 2008	Calendar 2009	Calendar 2010	Calendar 2011	Calendar 2012	Calendar 2013
1.	Total Customers (Average)	1 824 789	1 865 020	1 887 605	1 926 294	1 960 378	1 984 734	2 020 962
2.1	Total General Service (10^6m^3)	8 314.8	8 806.0	9 129.2	8 757.0	9 420.8	9 356.7	9 285.2
2.2	Total Contract (10^6m^3)	3 758.5	3 101.5	2 205.6	2 183.6	2 082.5	1 943.4	1 945.5
2.	Total Volumes (10^6m^3)	12 073.3	11 907.5	11 334.8	10 940.6	11 503.3	11 300.1	11 230.7
3.	Degree Days	3 613	3 750	3 764	3 454	3 639	3 532	3 481

Witnesses: R. Fischer
M. Lister
D. Yaworski



Witnesses: R. Fischer
M. Lister
D. Yaworski

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Ref: Ex. E2 /Tab 1/ Sch 2 / para 37

Enbridge in this paragraph refers to the possibility of a credit rating downgrade. Please provide evidence of any past credit rating downgrades or threats of downgrades for Enbridge and the reasons why it was downgraded (or threatened to be downgraded).

RESPONSE

DBRS downgraded EGD's rating in 2001 (from "A" high to "A") and S&P downgraded EGD's rating in 2002 (from "A" to "A-").

The associated rating agency reports that describe reasons for the downgrades are attached, as Attachments 1 and 2.

The Board may also find Attachment 3, entitled, Industry Study: Assessing Regulatory Risk in the Utilities Sector, published by DBRS in May 2012, useful and informative.

The report is informative as to what the rating agencies look at when they evaluate regulatory risk, which is one component of business risk. This report highlights ten key criteria that are reviewed by DBRS to assess a utility's regulatory risk. The ten criteria include:

- Deemed Equity
- Allowed Return (ROE) on Deemed Equity
- Fuel and Purchased Power (or Gas) Cost Recovery Certainty and the Timing of the Recovery
- Cost of Service (COS) versus Incentive Regulation Mechanism (IRM)
- Capital Cost Recovery (CCR)
- Political Interference

Witnesses: R. Fischer
M. Lister
D. Yaworski

- Retail Rate
- Stranded Costs
- Rate Freeze
- Market Structure (Deregulation)

The report describes the ten key criteria and also provides a measurement or rating scale for each of the ten criteria. Using the scale provided, the following can be determined:

Deemed Equity – At 35% in 1993, the Deemed Equity would be graded, “Good”. A 1% improvement in the equity ratio to 36% did not change the business risk assessment, and the Deemed Equity continues to be graded in the “Good” category.

Allowed ROE – In 1993, the Allowed ROE was 12.3%. This would represent an “Outstanding” grade in the business risk assessment. For the 2013 Test Year, the updated forecast for the Formula ROE is 9.03%, which is a notch down in the “Excellent” category, and only just slightly above “Good”.

Gas Costs – In the early 1990’s, Gas costs were reviewed in annual rate cases, and any variances were captured in a Purchased Gas Variance Account (PGVA). If the PGVA triggered a certain threshold then a review of the PGVA would be undertaken in advance of the next annual rate case. According to the DBRS rating methodology, this treatment of Gas Costs would result in a “Good” rating, whereas, in the present day, the DBRS assessment of the treatment of gas costs would be considered “Very Good”, because today adjustments are made on a quarterly basis. This, then, represents one area, where since 1993 there has been an improvement in the business risk.

COS vs. IR – In 1993, EGD had its rates set on a COS basis. DBRS would score this with an “Outstanding”. EGD has just completed a 5-year Incentive Regulation Plan and anticipates that the Board would expect to continue with Incentive Regulation in the future. A 5-year plan would score in the “Very Good” category, 2 notches down from the 1993 grade.

Capital Cost Recovery – With the Cost of Service regulatory framework in place in 1993, the DBRS business risk would likely have been rated as “Excellent”. Capital was pre-approved by the regulator in the Test Year rate case, added to rate base at the completion of work, with a reasonable mechanism to deal with any cost overruns. In the present day, with the continuation of incentive regulation, the treatment of capital costs imposes greater risk on the utility. In incentive regulation capital expenditures for the Test Year are generally pre-approved, however, subsequent to the Test Year the utility

Witnesses: R. Fischer
M. Lister
D. Yaworski

runs the risk that certain expenditures, or the productivity effects of such spending, may be called into question. Relative to annual COS treatment, the utility assumes greater risk in an Incentive Regulation framework, which would move the DBRS business risk assessment to “Very Good”.

Political Interference – In 1993, there was little government involvement in the privatized utility sector. With little change in the present day with respect to political interference, the rating for this factor would like remain in the “Outstanding category.”

Retail Rate – The scale that is provided directly refers to electricity prices. However, it is reasonable to assume that a grade awarded in 1993 would have been in the “Outstanding” or “Excellent” categories, with low gas prices and robust system expansion. Today, gas prices currently remain low, but the level and volatility of gas commodity prices in the intervening years, the increasing costs associated with ageing infrastructure, and increasing rates associated with declining average uses would lower the grade at least one notch from its starting position.

Stranded Costs – Generally, there has been no change in the treatment of stranded costs. There have been some disallowances over time, but those are rare. It is reasonable to put a grade for this item in either the “Excellent” or “Very Good” categories for both 1993 with no change in the present day.

Rate Freeze – Rates in the gas distribution sector have not been frozen since 1993. This category would earn an “Outstanding” assessment in both 1993 and in 2013.

Market Structure (Deregulation) – In 1993, the gas supply market would have been considered deregulated since industrial and large volume customers could access their own gas supplies. Since 1993, the presence of retail gas supply options in Ontario further deregulated the gas supply market. It is reasonable to assume that a grade of “Very Good” would be appropriate for both the 1993 and present day scenarios.

The conclusion is that several of the ten key criteria have resulted in higher business risk than that which existed in 1993. Namely, the Allowed ROE has declined significantly, the movement towards IR has increased risk, and rates have been increasing due to declining average uses and ageing infrastructure costs. While risk has been reduced with respect to a standardized quarterly review of Gas Costs, on a net basis there has been a clear increase in business risk.

Witnesses: R. Fischer
M. Lister
D. Yaworski

STANDARD & POOR'S CANADIAN RATINGS

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Analysis

Consumers Gas Co. Ltd. (The)

Analyst: Jenny Catalfo, Toronto (1) 416-507-2557; Michelle Dathorne, Toronto (1) 416-507-2563

Credit Rating
A-/Negative/--

Rationale

The corporate credit rating on The Consumers' Gas Co. Ltd. reflects the consolidated business and financial risk profile of parent Enbridge Inc., given a lack of sufficient regulatory insulation. The parent and operating company credit profiles are further linked by the existence of material intercorporate transactions and because, ultimately, Enbridge is responsible for maintaining a common equity thickness at the regulated gas distribution operations reflective of regulatory guidelines. As a result, the ratings on Consumers' Gas are equalized with those on Enbridge.

The ratings on Consumers' Gas also reflect the company's strong business position and its below-average financial profile, and the rating constraints imposed by Enbridge. Consumers' Gas' strong business profile is supported by one of the most attractive business franchises in Canada, characterized by favorable growth prospects, a 95% market share for natural gas in the new home market, and a high population density, all of which make the company one of the most efficient operators in the Canadian gas distribution industry. In addition, regulation allows for the full and timely pass through of fuel costs so Consumers' Gas is not exposed to commodity price risk.

The company's below-average financial profile reflects regulatory guidelines that require Enbridge to maintain a capital structure at the regulated gas distribution operations that reflects a 35% deemed common equity. The 65% debt-to-capital ratio (inclusive of all preferred shares) constrains cash flow protection measures, but ratios should remain relatively stable in the longer term and the preferred shares enhance the company's financial flexibility.

Consumers' Gas is the largest gas distributor in Canada with about 1.5 million customers, and is regulated on a cost of service/rate of return performance-based regulatory methodology. The company's Ontario-based service franchise covers the metropolitan Toronto region in addition to the Niagara Peninsula and the Ottawa-to-Peterborough area.

Outlook

Although warmer-than-normal winter temperatures can adversely affect earnings and cash flows during the short term, Consumers' Gas' long-term outlook is supported by a relatively stable financial profile, considering regulatory directives regarding the operating company's equity thickness. Consumers' Gas' credit profile and ratings will, however, continue to be influenced by the ratings on parent Enbridge, while the introduction of more rigorous performance-based regulation could adversely affect the company's strong business profile.

Table 1 The Consumers' Gas Co. Ltd. Financial Summary

	--Year ended Sept. 30--				
(Mil. C$)	2001	2000	1999	1998	1997
Gross revenues	2,514.9	1,767.3	1,860.9	1,771.7	1,986.8
Net income from cont. operations	174.1	129.3	113.8	97.2	140.6
Funds from operations (FFO)	368.8	324.3	374.5	278.1	304.1
Net cash flow (NCF)	241.6	(30.4)	277.0	194.4	225.5
Capital expenditures	267.1	233.0	356.1	390.0	405.2
Total capital	4,327.2	3,804.7	4,018.0	3,541.5	3,143.1
Pretax interest coverage (x)	2.8	2.2	2.1	2.1	2.6
Total debt (incl. STD)/capital (%)	51.2	57.6	59.4	67.8	64.1
FFO/interest coverage (x)	3.3	2.8	3.0	2.6	2.9
FFO/avg. total debt (%)	16.7	14.2	15.6	12.6	15.6
NCF/capital expenditures (%)	90.8	(13.0)	77.8	49.8	55.7

STD--Short-term debt. NCF--FFO less dividends; 2000 includes the impact of a special dividend payout.

Rating Methodology

The corporate credit rating on Consumers' Gas reflects the consolidated business and financial risk profile of parent Enbridge, given a lack of sufficient regulatory insulation. The parent and operating company credit profiles are further linked by the existence of material intercorporate transactions and the fact that ultimately, Enbridge is responsible for maintaining a common equity thickness at the regulated gas distribution operations reflective of regulatory guidelines. As a result, the ratings on Consumers' Gas are equalized with those on Enbridge.

Business Description

Consumers' Gas is the largest regulated gas distributor in Canada. The utility has one of the most attractive service franchises in Canada, based in Ontario, and covers metropolitan Toronto and surrounding suburbs, as well as the Niagara Peninsula and the Ottawa-to-Peterborough area along the Ontario-Quebec border. Consumers' Gas also delivers gas (wholesale) to customers in northern New York. The company is wholly owned (indirectly) by Enbridge.

Business Profile

The company's business profile is one of the strongest of all Canadian distribution utilities based on the following considerations.

Regulation.

The Ontario natural gas market is fully unbundled and deregulated, and retail choice has been in effect since the mid-1980s. Consumers' Gas is not permitted to participate in energy marketing, but as a provider of last resort, the company bears no price risk for the sale of the commodity. Variances in gas costs versus forecasts accumulate in a deferral account with rate adjustments made on a quarterly basis, with regulatory approval, to recover outstanding balances in a timely fashion.

Performance-based regulation (PBR) introduced for 2000-2003 subjects Consumers' Gas to certain operating risks; base (2000) operating, maintenance, and administrative expenses are adjusted annually by the rate of inflation (Ontario CPI) and customer growth, offset by a 1.1% productivity factor. The utility retains all cost savings during this period, but bears the burden of costs exceeding established targets. Consumers' Gas comfortably exceeded these cost targets during 2000 and 2001. A more comprehensive PBR is expected to be introduced for the period after 2003. Base operating costs will likely be reset for the next generation of PBR to reflect the achieved improvement in operating efficiencies. A more comprehensive PBR mechanism could increase Consumers' Gas' exposure to operating risks, which could potentially affect the credit ratings.

Formula-driven approved ROEs, introduced for 1998, are set annually based on a 371 basis point equity risk premium over forecast 10-year Government of Canada bond yields as published in the August issue of Consensus Forecasts. Based on this methodology, the applicable ROE for 2002 would be about 9.66%. Consumers' Gas has filed an application, asking the Ontario Energy Board (OEB) to review the ROE formula; the utility is asking for an approved ROE of 11.38%. Although formula-based ROEs eliminate the potential for subjectivity on the part of regulators and minimize regulatory lag, the direct link to benchmark Government of Canada bond yields makes earnings sensitive to the movement of interest rates. The forward test year basis exposes the company to forecast risk, largely with respect to economic and customer growth assumptions. These variances from forecasts are not recoverable.

Deemed equity is set at 35% with a requested 9.32% return on rate base of around C$3.1 billion for 2002. Enbridge has entered into specific written undertakings with the Ontario provincial government and through OEB regulation to maintain the common equity component of the regulated business' balance sheet at 35%, and to restrict operating activities of Consumers' Gas to the distribution, storage, and transmission of natural gas (all regulated).

Markets.
Ontario economic growth has consistently been one of the strongest, if not the strongest, in Canada. Long-term real GDP growth, per capita income, and population growth are well above the national average, while Ontario's unemployment rate is low relative to the national average. Housing starts, one of the leading indicators of customer growth, are also among the strongest in Canada. Natural gas is the fuel of choice for home heating (95% of all new homes) and among many industrials.

Consumers' Gas has a diversified base of 1.5 million customers; the 20 largest customers account for less than 10% of throughputs and about 1% of gross revenues. The utility's customer growth rate is among the highest in Canada, consistently above 3% annually. The customer mix is heavily weighted toward residential and commercial segments, which provide stability throughout the economic cycle. Nevertheless, the high residential and commercial concentration contributes to short-term cash flow variability as a result of the earnings sensitivity to winter temperatures. Consumers' Gas has the highest earnings sensitivity to temperatures of all Canadian gas distributors. A 5% change in degree days (a measure of coldness) would affect annual net earnings by about C$12 million. Regulatory mechanisms (weather forecasting methodology used in financial forecasts for regulatory purposes) allow for the long-term recovery of the adverse earnings effect from warmer-than-normal winter temperatures.

Table 2 The Consumers' Gas Co. Ltd. Market Segments

	2001	2000	1999	1998	1997
Energy sales					
Residential (%)	35.5	34.0	33.3	32.7	33.5
Commercial (%)	39.7	38.8	38.8	38.0	38.3
Industrial (%)	24.8	27.2	27.9	29.3	28.2
Total (billions of cubic feet)	425.5	421.2	401.6	396.6	428.4
Annual growth (%)	1.0	4.9	1.3	(7.4)	0.1
Degree days* (%)	98.1	90.8	85.2	82.2	100.2
Gross revenues					
Residential (%)	55.0	54.5	47.4	46.3	45.6
Commercial (%)	32.9	31.3	28.0	29.6	32.8
Industrial (%)	10.0	10.7	9.4	10.3	10.9
Nonenergy (%)	2.1	3.6	15.1	13.8	10.7
Total (Mil. C$)	2,514.9	1,767.3	1,860.9	1,771.7	1,986.8
Annual growth (%)	42.3	(5.0)	5.0	(10.8)	2.6
Customers					
Total (thousands)	1,546.3	1,497.4	1,443.2	1,392.5	1,341.8
Annual growth (%)	3.3	3.8	3.6	3.8	4.1

*Degree days is a measure of coldness relative to long-term averages. Values above 100% reflect colder-than-normal temperatures.

Operations.
Consumers' Gas' franchise region has the highest population density in Canada, which contributes to a low cost structure and ultimately competitive energy delivery rates. The company consistently ranks number one on the basis of customer per employee and operating costs per average customer efficiency measures relative to other Canadian gas distributors.

Most operating risks are offset by supportive regulation including long-term weather related volume variances and gas cost variances. Variances associated with economic and customer growth assumptions (forecast risk) are not recoverable and must be diligently managed through cost control efforts.

Gas supply sources are varied, with prices generally indexed against Alberta prices. New pipeline construction (such as the Alliance Pipeline from British Columbia to Chicago, Ill.; Vector Pipeline from Chicago, Ill. to Dawn, Ont.; and the Link Project from southwestern Ontario to ANR Pipeline Co.'s southeast and southwest pipelines) should improve sourcing alternatives. Supply contract mix (spot versus fixed) and tenure are reviewed and approved by the OEB.

Table 3 Operating Efficiencies of Canadian Gas Distributors

	--At Dec. 31, 2000--					
	Operating costs* per avg. customer (C$)	Rank	Customers per employee	Rank	EBITDA margin (%)	Rank
AltaGas Utilities Inc.	234.4	3	419	6	15.9	9
BC Gas Utility Ltd.	209.5	2	521	2	24.6	5
Centra Gas British Columbia Inc.	519.7	7	289	9	34.8	1
Centra Gas Manitoba Inc.¶	251.1	4	375	8	11.5	10
Consumers' Gas Co. Ltd. (The)§	193.0	1	846	1	29.5	3
CU Inc. (gas only)	353.7	6	450	5	17.2	8
Gaz Metropolitain Inc.**§	784.9	10	127	10	20.1	6
Pacific Northern Gas Ltd.	590.5	8	451	4	26.5	4
Saskatchewan Energy	609.8	9	394	7	17.6	7
Union Gas Ltd.	291.9	5	509	3	30.5	2
Canadian averages	301.0		481		23.6	

*Operating, maintenance, and administrative costs only. ¶At March 31, 2000. §At Sept. 30, 2000. **Distribution operations only, inclusive of Vermont.

Competitive position.
Natural gas has a strong price advantage over other fuel alternatives and is the fuel of choice for home heating within the company's service franchise (95% of all new homes). This price advantage should remain particularly strong against electricity given that industry restructuring in Ontario to date has resulted in sharply higher electricity rates. Oil (for dual fuel industrial customers) is potentially a more material competitive threat; however, Consumers' Gas' industrial customer segment in total only accounts for 11% of gross revenues. PBR, with its focus on cost efficiencies, should help the utility improve its competitive position in the longer term.

Although energy marketers have made significant inroads in Ontario during the past few years, (transportation services accounted for 57% of total throughputs in 2001 compared with 5% in 1992), retail choice has had no effect on Consumers' Gas' earnings or cash flows because the utility is not allowed to profit (nor is the company exposed to the associated commodity price risk) from the sale of the commodity.

Financial Profile

Financial Policy: Below average
Consumers' Gas' financial profile is materially weaker than its business profile. Nevertheless, the balance-sheet strength of Canadian utilities is largely dictated by regulatory guidelines (deemed equity components). There is little to no incentive to diverge from these directives; "excess" equity generates a lower return than the approved ROE while successfully operating with less than the deemed equity may signal that the allowed equity cushion is too thick. The somewhat aggressive use of leverage by Canadian utilities has historically been supported by monopoly service franchises and stable industry fundamentals. PBR is, however, increasing the company's business risk profile.

Most regulated operating utilities in Canada, including Consumers' Gas, are not widely held (these utilities access public debt markets but common shares are held by a parent). Consumers' Gas' parent, Enbridge, is expected to maintain the equity component of the regulated operating company at specified levels. Thus, the financial strength of Enbridge is a key consideration.

Profitability and cash flow protection.
Profitability, and to a lesser extent cash flows, were constrained during 1998-2000 due to abnormally warm winter temperatures, but returned to more normal levels in 2001 with temperatures at near normal levels. The variability during the period reflects the company's earnings and cash flow sensitivity to winter temperatures. The transfer of the water heater rental business to an unregulated affiliate at the end of fiscal 1999 materially increased Consumers' Gas' earnings sensitivity to temperatures.

The utility's cash flow protection measures adequately reflect the current credit ratings, and the business profile takes into consideration the fact that warmer-than-normal winter temperatures can cause material swings in these ratios. The introduction of a more rigorous PBR mechanism could affect the company's business profile; a weaker business profile would require a more robust financial profile to maintain the same credit rating.

Capital structure and financial flexibility.
Intercorporate transactions are increasingly reflected in the consolidated capitalization of Consumers' Gas. Enbridge manages the utility's debt-to-capital ratio through dividend payments and equity injections to maintain and reflect the allowed 35% common equity component. Consumers' Gas' consolidated capitalization at September 2001 included C$870 million of intercorporate investments funded by C$422 million in affiliate (IPL System Inc.) subordinate loans (hybrid preferred shares) and C$448 million of common equity (from Enbridge). On a consolidated basis, debt to capital has declined materially during the past year as a result of a greater reliance on intercorporate preferred shares. These preferred shares materially enhance Consumers' Gas' financing flexibility; interest payments may be deferred for up to five years and outstanding balances may be paid in preferred shares. An affiliate code of conduct restricts intercorporate investments to 25% of Enbridge's equity investment in Consumers' Gas. Consumers' Gas also has a C$650 million commercial paper program, supported by committed bank lines of credit. Commercial paper borrowings are used primarily for working capital purposes and are highly seasonal. Total debt to capital including preferred shares is expected to remain relatively stable and will continue to reflect regulatory guidelines.

Table 4 The Consumers' Gas Co. Ltd. Profitability					
	--Year ended Sept. 30--				
	2001	2000	1999	1998	1997
Income statement (mil. C$)					
Gross revenues	2,514.9	1,767.3	1,860.9	1,771.7	1,986.8
Operating expenses (excl DD&A)	1,963.2	1,246.0	1,283.1	1,220.6	1,401.8
Depreciation and amortization	159.0	176.8	214.8	196.8	169.7
EBIT	392.7	344.5	363.0	354.4	415.3
Gross interest expense	158.8	177.8	184.1	170.4	159.8
AFUDC and other income/expense	48.8	56.7	25.6	3.8	5.4
Pretax income	282.7	223.4	204.5	187.8	260.8
Income taxes	108.6	94.1	90.6	90.7	120.2
Net income from cont. oper.	174.1	129.3	113.8	97.2	140.6
Earnings protection					
EBIT interest coverage (x)	2.8	2.2	2.1	2.1	2.6
Preferred dividend coverage (x)	2.4	2.0	2.0	2.0	2.5
EBITDA interest coverage (x)	3.8	3.2	3.2	3.2	3.7
AFUDC and other income/earnings (%)	28.0	43.9	22.5	3.9	3.8
Return on avg. common equity (%)	12.0	9.8	9.6	9.4	14.4
Pretax return on avg. capital (%)	10.8	10.1	10.1	10.6	13.7
Common dividend payout (%)	52.6	260.6	80.0	80.4	52.1
Annual expense growth (excl. DD&A) (%)	57.6	(2.9)	5.1	(12.9)	(0.1)
Operating expenses (excl. DD&A)/revenues (%)	78.1	70.5	69.0	68.9	70.6
DD&A--Depreciation, depletion, and amortization. AFUDC--Allowance for funds used during construction.					

Table 5 The Consumers' Gas Co. Ltd. Cash Flow Protection					
	--Year ended Sept. 30--				
	2001	2000	1999	1998	1997
Cash flow (mil. C$)					
Net income	174.1	129.3	113.8	97.2	140.6
Depreciation and amortization	159.0	176.8	214.8	196.8	169.7
Other noncash items	35.7	18.2	45.8	(15.9)	(6.2)
Funds from operations (FFO)	368.8	324.3	374.5	278.1	304.1
Preferred dividends	23.1	17.7	12.6	6.6	6.7
Common dividends	103.3	337.0	84.9	77.1	71.9
Net cash flow (NCF)	242.4	(30.4)	277.0	194.4	225.5
Working capital changes	(387.2)	(85.5)	(17.3)	(163.0)	19.4
Capital expenditures	267.1	233.0	356.1	390.0	405.2
Discretionary cash flow	(411.9)	(348.9)	(96.4)	(358.7)	(160.3)
Cash flow adequacy					
FFO interest coverage (x)	3.3	2.8	3.0	2.6	2.9
FFO interest + pfd coverage (x)	3.3	2.4	2.7	2.5	2.7
FFO/avg. total debt (%)	16.7	14.2	15.6	12.6	15.6
FFO/avg. total debt + pfd shares(%)	14.1	12.5	14.4	12.0	14.8
NCF/capital expenditures (%)	90.8	(13.0)	77.8	49.8	55.7

Table 6 The Consumers' Gas Co. Ltd. Capital Structure

	--Year ended Sept. 30--				
	2001	2000	1999	1998	1997
Balance sheet (Mil. C$)					
Cash	0.0	0.0	0.0	51.0	1.0
Gross plant	3,836.3	3,774.6	4,490.8	4,208.4	3,874.7
Net plant	2,698.2	2,692.5	3,235.2	3,094.0	2,900.7
Total assets	4,785.6	4,367.7	4,507.6	3,928.5	3,542.2
Short-term debt	566.5	495.7	497.9	453.5	607.9
Long-term debt	1,649.5	1,696.5	1,889.5	1,946.3	1,408.1
Preferred equity (incl. intercorporate COPrS)	520.0	300.0	300.0	104.0	105.2
Common equity	1,591.2	1,312.5	1,330.6	1,037.7	1,021.9
Total capitalization	4,327.2	3,804.7	4,018.0	3,541.5	3,143.1
Total off-balance-sheet obligations	0	0	0	0	0
Balance-sheet ratios					
Short-term debt/total capital (%)	13.1	13.0	12.4	12.8	19.3
Long-term debt/total capital (%)	38.1	44.6	47.0	55.0	44.8
Total debt/total capital (%)	51.2	57.6	59.4	67.8	64.1
Preferred stock/total capital (%)	12.0	7.9	7.5	2.9	3.3
Common equity/total capital (%)	36.8	34.5	33.1	29.3	32.5
Adjusted total debt/total capital (%)	51.2	57.6	59.4	67.8	64.1

COPrS--Canadian originated preferred securities.

Table 7 Comparative Statistics--Canadian Gas Distribution Companies

	--Year ended Dec. 31, 2000--						
(Mil. C$)	CU Inc.	The Consumers' Gas Co. Ltd	Union Gas Ltd.	Gaz Metropolitain Inc.	BC Gas Utility Ltd.	Pacific Northern Gas Ltd.	Standard & Poor's Financial Mean*
Corporate credit ratings as of Jan. 8, 2002.	A+/Stable/A-1	A-/Negative/--	A-/Watch Pos/--	A-/Stable/--	BBB+/Stable /--	BB-/Watch Pos/--	A
Gross revenues	2,248.0	1,923.5	1,614.0	1,851.5	1,085.3	115.7	N.M.
Net income (before extraordinary items)	166.8	145.0	113.0	145.0	61.9	6.8	N.M.
Funds from operations (FFO)	380.3	343.6	237.0	283.8	124.1	18.5	N.M.
Net cash flow (NCF)¶	253.6	46.0	167.0	146.8	64.0	16.2	N.M.
Capital expenditures	241.8	244.3	204.0	90.2	472.5	7.9	N.M.
Total capital	3,563.5	3,861.1	3,365.0	2,159.5	2,325.9	184.3	N.M.
NCF/capital expenditures (%)	104.9	18.8	81.9	162.8	13.5	205.8	69.6
Pretax interest coverage (x)	2.8	2.4	2.0	2.5	2.0	2.3	3.8
FFO interest coverage (x)	3.4	3.0	2.3	4.0	2.1	2.9	4.1
FFO/avg. total debt (%)	20.6	15.2	11.0	22.8	9.0	15.9	20.2
Total debt (incl. STD)/capital (%)	55.6	58.1	65.8	61.4	67.3	59.9	48.8
Total debt (incl. STD+PFD)/capital (%)	62.8	65.9	69.6	61.4	67.3	62.6	49.7

*Published July 7, 2000. N.M.—Not meaningful. ¶NCF--FFO less all dividends. STD--Short-term debt. PFD--Preferred shares.

Rating Detail

Publication Date 09-Jan-2002

Consumers Gas Co. Ltd. (The)

Analysts: Jenny Catalfo, Toronto (1) 416-507-2557 ; Michelle Dathorne, Toronto (1) 416-507-2563

Corporate Credit Rating

A-/Negative/--

Business Profile

1 $\boxed{2}$ 3 4 5 6 7 8 9 10

Outstanding Rating(s)

Consumers Gas Co. Ltd. (The)

Sr unsecd debt A-

Local currency

Pfd stk BBB

Local currency

Corporate Credit Rating History

Jan. 23, 2001	A
Dec. 18, 2001	A-

Company Contact:
Al Monaco, (1) 403-231-3973

Standard & Poor's
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Bond, Long Term Debt and Preferred Share Ratings

The Consumers' Gas Company Ltd.

Current Report: January 9, 2001
Previous Report: March 17, 2000

RATING

Rating	*Trend*	*Rating Action*	*Debt Rated*
"A"	Stable	Downgraded	Unsecured Debentures & Medium Term Notes
Pfd-2	Stable	Downgraded	Preferred Shares - Cumulative, Redeemable

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RATING HISTORY (as at Dec. 31)	*Current*	*2000*	*1999*	*1998*	*1997*	*1996*
Unsecured Debentures & MTNs	"A"	A (high)	A (high)	A (high)	A (high)	A (high)
Preferred shares	Pfd-2	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)*	Pfd-2	Pfd-2

* On October 1, 1998, DBRS broadened its preferred share rating scale, resulting in technical changes to the Utility's preferred share ratings.

RATING UPDATE

DBRS is downgrading the long-term debt preferred share credit ratings of the Consumers' Gas Company Ltd. ("Consumers' Gas" or "the Utility") to "A" and Pfd-2, with Stable trends, from A (high) and Pfd-2 (high), respectively. The ratings adjustments are based on the following considerations. Earnings volatility from traditional business risks such as weather and economic conditions has increased as a percentage of base earnings following the transfer of ancillary businesses to affiliates during F2000 and due to a decline in approved ROEs over the last five years. The steady decline in approved ROEs, consistent with the trend in long-term interest rates, has adversely affected earnings over the period. These factors, in combination, have resulted in a decline in certain key financial ratios from weather normalized historical highs. A slowdown in the Canadian economy could potentially lead to a further decline in interest rates and approved ROEs.

While working capital needs have increased recently due to a very sharp increase in the cost of natural gas inventories that are generally financed with short-term debt, DBRS expects little material change in balance sheet leverage given the nature of the industry. The Utility's primary challenge is its earnings sensitivity to weather, given that roughly 70%-75% of distribution volumes are delivered to temperature sensitive residential and commercial customers. While the forecasting methodology adjusts for variations so that the earnings impact is moderated over a five-year period, temperature variability can contribute to material short-term earnings volatility and can significantly affect key financial ratios. The Utility's long-term outlook remains favourable, given one of the most attractive business franchises in Canada characterized by strong economic fundamentals.

RATING CONSIDERATIONS

Strengths:
- Regulation contributes to earnings/financial stability, PBR reduces regulatory administrative and cost burden
- Attractive business franchise; strong economic growth, high population density, heavily weighted by higher margin residential customers
- Competitive advantages of gas versus alternative fuels

Challenges:
- Earnings sensitivity to temperatures (75% of gas throughputs) and interest rates (approved ROEs)
- Forecast risk: no deferral accounts to adjust for weather related volume variances
- Tax methodology results in unrecorded (potentially unrecoverable) tax liabilities, weakens interest coverage

FINANCIAL INFORMATION	Industry Avg.*	For years ended September 30				
	Sep-00	2000	1999	1998	1997	1996
Fixed Charges Coverage (times)	*1.95*	1.99	1.98	1.97	2.46	2.42
% Adjusted Debt in Capital Structure (1)	*63.5%*	57.9%	59.7%	70.7%	67.5%	68.2%
Cash Flow/Adjusted Total Debt (times) (1)	*0.13*	0.14	0.15	0.11	0.14	0.15
Cash Flow/Capital Expenditures (times)	*1.09*	1.34	1.03	0.70	0.73	0.83
Approved ROE	-	9.73%	9.51%	10.30%	11.50%	11.88%
Operating Income ($ millions)	-	344.5	362.9	354.4	415.3	399.9
Net Income ($ millions) (after pfd divs.)	-	117.2	105.2	90.8	134.2	140.8
Operating Cash Flow ($ millions) (after pfd divs.)	-	312.3	366.9	271.7	297.7	302.3
Throughput Volumes (Bcf)	-	421.2	401.6	396.6	428.4	428.2

* DBRS Industry composite for Cdn. gas distributors. (1) Adjusted for equity treatment of hybrid debt securities.

THE COMPANY The Consumers' Gas Company Ltd. is a natural gas distributor, whose franchise covers central, eastern and the Niagara Peninsula regions of Ontario. The Utility also services distributors outside its franchise region through a subsidiary in New York. The Consumers Gas Company Ltd. is a wholly-owned subsidiary of Enbridge Inc. (see separate report).

REGULATION

The Consumers' Gas Company Ltd. is regulated by the Ontario Energy Board ("OEB"), based on a cost of service methodology. The Utility's approved capitalization has been set at 65% debt (including 3% preferred equity) and 35% common equity. Based on the current methodology, the approved ROE for F2001 would be in the 9.6% range, compared to 9.73% for F2000. The Utility has submitted a proposal to the OEB to modify the methodology of the ROE mechanism. The proposed change involves the use of the historical spread between ten- and thrity-year bonds, rather than the observed spread (defined below), which is currently negative as a result of the yield curve inversion.

Effective F1998, the OEB adopted a formula-based mechanism to determine approved ROEs. The mechanism consists of two components: (1) The (typically) August Consensus Forecast yield for ten-year bonds plus the market spread between the ten- and thirty-year bond yields; and (2) an equity risk premium, set at 371 basis points for F2001 and for F2000. The ROE formula has been designed to capture 75% of the year-over-year movement in interest rates.

Like other gas utilities, Consumers' Gas is protected from gas price variations that differ from forecasts. Variations accumulate in a deferred account, with price adjustments made as required (whenever forecast year-end balances exceed $35 per average residential customer). Weather-related volume variances are not recoverable.

During F1999, the Utility received regulatory approval to unbundle certain ancillary businesses and transferred these operations ($737 million net book value) to an affiliated entity, Enbridge Services Inc, in October 1999. Certain administrative functions (billing and customer services, and associated assets and employees) were also transferred to another affiliated entity, Enbridge Commercial Services Inc., in January and October 2000.

Effective for F2000-F2002, Consumers' Gas became subject to performance-based regulation ("PBR"). The system establishes a base for operating and maintenance costs that will be adjusted annually by the rate of inflation and customer growth, offset by a 1.1% productivity factor. The Utility is not required to share any cost efficiencies in excess of the 1.1% productivity targets, but the cost of service will likely involve a negotiated re-basing at the end of the three-year period to take into account achieved operating efficiencies. The OEB expects the Utility to develop and implement (subject to regulatory approval) a more comprehensive PBR plan for no later than F2003. Overall, DBRS views PBR mechanisms favourably as they encourage operating efficiencies and reduce a Utility's regulatory burden.

RATING CONSIDERATIONS

<u>Strengths</u>: (1) *Cost of service regulation contributes to relative earnings and financial stability.* The recent implementation of a PBR mechanism and the use of formula-based ROEs minimize the related administrative and cost burden and contribute to financial stability. PBR minimizes regulatory lag, streamlines the regulatory process, and encourages utilities to improve operating efficiencies. Regulation also allows for the recovery (and/or remittance to customers) of variances from forecasts in prudently incurred gas costs. Variances are normally recovered within a one-year period.

(2) *Attractive business franchise.* Consumers' Gas franchise, consisting of central, eastern and the Niagara Peninsula regions in Ontario, has a number of attractive characteristics: (a) It is one of the fastest growing regions in the province, in terms of both demographics and economic prosperity. (b) The region has a high population density, which contributes to a competitive cost structure. (c) The Utility's customer profile and revenues are heavily weighted with the higher margin, more stable residential and commercial customer categories. As a result, the Utility's earnings have a relatively low exposure to the economic cycle, but are highly sensitive to weather.

(3) *Competitive advantages of gas versus alternative sources of energy.* In spite of the sharp increase in gas prices over the past year, natural gas remains the most economical fuel source for home heating and is more environmentally friendly than oil and nuclear-based power. However, the Company will likely face competitive pressures in the dual fuel industrial customer segment particularly if oil prices continue to fall and gas prices remain high.

<u>Challenges</u>: (1) *Sensitivity to temperatures.* Almost 75% of distribution throughputs are delivered to temperature sensitive residential and commercial customers. The weather forecasting methodology used adjusts for short-term temperature fluctuations so that the earnings impact is moderated over future years. Over the short-term, temperature volatility can contribute to significant fluctuations in earnings, cash flows and interest coverage ratios. Warmer than normal temperatures have adversely affected earnings for the last three consecutive winters (F1998-F2000). A 5% change in degree days would impact net earnings by about $11 million.

(2) *Sensitivity to interest rates.* Approved ROEs have been falling steadily over the last few years, consistent with the trend in long-term interest rates, negatively impacting interest coverage ratios over the period. A 25 basis point change in the approved ROE would impact net earnings by about $2.5 million. Note that this sensitivity increases along with growth in the rate base. An economic slowdown and/or recession in Canada could lead to a further decline in interest rates and approved ROEs.

(3) *Forecast risk.* The accuracy of forecast distribution volumes is a key business risk, given the forward test year method of rate setting used in Ontario. The ability to realize the approved rate of return is dependent on achieving the forecast volumes to generate the revenues required to recover the cost of providing the services. Achievement of forecast distribution volumes is contingent upon weather and economic conditions. While the risk is partially mitigated by flexibility of gas supply contracting practices,

Consumers' Gas is exposed to demand risk as there are no deferral accounts to adjust for volume variances associated with warmer than forecast temperatures.

(4) *Tax accounting methodology adversely impacts interest coverage ratios.* The use of the direct flow through method of taxation has resulted in an unrecorded deferred income tax liability of $472 million as at September 2000. The direct flow through method of taxation results in lower revenue collections, thereby reducing operating income and weakening coverage ratios. The recovery of this liability in future rates is not assured. Note that the unbundling and transfer of ancillary businesses during F2000 involved $168 million and is related to unrecorded deferred income taxes. Although the Utility is contesting the decision in the courts, the OEB ruled that only $50 million is recoverable in future rates and another $42 million can be offset by Revenue Canada's change in tax assessment practices, while the remainder, $76 million, is the responsibility of the shareholder (i.e. charged against retained earnings).

EARNINGS

Income Statements	For years ended September 30						
($ millions)	2000	1999	1998	1997	1996	1995	1994
Residential	846.8	811.4	789.9	906.6	903.8	807.3	878.9
Commercial	430.8	427.9	471.9	645.0	637.3	627.2	685.7
Industrial	116.7	115.5	135.4	198.1	197.2	251.2	277.9
Gross gas revenues	**1,394.2**	**1,354.8**	**1,397.2**	**1,749.8**	**1,738.3**	**1,685.7**	**1,842.5**
Cost of gas	**962.3**	**899.3**	**861.8**	**1,036.3**	**1,063.4**	**1,123.4**	**1,254.9**
Net gas revenues	**431.9**	**455.5**	**535.3**	**713.5**	**674.9**	**562.2**	**587.6**
Transportation service	**309.9**	**224.5**	**130.1**	**24.5**	**12.1**	**12.6**	**9.5**
Total gas revenues	741.8	679.9	665.5	738.0	686.9	574.9	597.1
Ancillary revenues	63.2	281.6	244.4	212.5	186.8	147.1	96.9
Total Revenues	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]
Expenses:							
Operations + maintenance	237.9	337.0	319.2	328.3	304.5	278.0	227.3
Property + other taxes	45.8	46.8	39.6	37.2	35.3	34.6	33.6
Depreciation + amortization	176.8	214.8	196.8	169.7	134.0	119.2	105.1
Total operating expenses	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]
Operating income (EBIT)							
Interest expense							
Non-cash financial charges							
Other (income)/expense (1)	[illegible]	(19.4)	[illegible]		[illegible]	[illegible]	[illegible]
Net interest expense		**158.5**		[illegible]	[illegible]	[illegible]	[illegible]
Pre-tax income							
Income taxes							
Net income							
Retractable preferred dividends							
Preferred dividends (2)							
Net income available to common shldrs	[illegible]	[illegible]	[illegible]	[illegible]	140.8	97.8	120.7
Throughput Volumes - Breakdown							
Residential **24%**	100.784	106.221	115.646	143.675	146.499	125.047	139.222
Commercial **16%**	65.483	73.461	95.101	142.440	145.899	132.972	145.194
Industrial/Wholesale **6%**	23.828	23.087	32.759	51.716	57.858	64.061	68.434
Gas Transportation **55%**	231.116	198.851	153.100	90.618	77.945	68.317	64.364
Total (billions of cubic feet)	[illegible]	[illegible]	396.607	[illegible]	[illegible]	[illegible]	[illegible]
Growth in volume throughputs	**4.9%**	**1.3%**	**-7.4%**	**0.1%**	**9.7%**	**-6.4%**	**7.8%**

(1) Inter-corporate investment income net of interest expense.

(2) Includes inter-corporate preferred securities dividends; 2000-$7.421 million, 1999-$4.861 million.

EBIT fell 5% to $344.5 million from $362.9 million last year, largely due to the transfer of certain ancillary businesses (primarily water heater rentals) to an affiliate, and despite several favourable factors: (1) Colder weather than last year (90.8% degree days normal compared to 85.2% last year). Temperatures were, however, still warmer than normal and reduced EBIT by almost $39 million. (2) Favourable economic conditions and housing starts in the franchise region, which contributed to a 3.8% increase in the customer base. (3) A 22 basis point increase in the approved ROE to 9.73% from 9.51%. (4) Approximately $16 million (pre-tax) in achieved operating efficiencies based on the defined PBR mechanism introduced for the F2000-F2003 period.

The decline in EBIT was more than offset by higher interest and dividend income from inter-corporate loans and investments, that resulted in an increase in net earnings after preferred share dividends from $105.2 million last year to $117.2 million. (Note that DBRS adjusts reported earnings for inter-corporate preferred securities dividends ($7.5 million in F2000, $4.9 million in F1999) that are charged against retained earnings).

Outlook: With about 70%-75% of distribution volumes delivered to temperature-sensitive residential and commercial customers, weather remains the primary factor that will influence earnings in F2001. Assuming a return to more normal temperature levels (temperatures over the 1Q F2001 were about 8.9% colder than normal), EBIT should improve materially in F2001. This will be somewhat offset by an expected ten basis point decline (equal to about $1 million in net earnings) in the approved ROE, while any change in the formula used to calculate the approved ROE (see Regulation) would positively impact earnings. The Utility should continue to generate PBR cost savings in each of the next two years. Over the near-term, earnings may be somewhat adversely affected by competitive pressures in the dual fuel industrial customer segment in light of rising gas prices, particularly if oil prices continue their recent downward trend. The associated volumes are a small component of total daily industrial throughputs (8%) so the impact is not expected to be significant. The actual earnings impact would be limited to the variance from associated volume forecasts that take these pressures into account. Net earnings should also continue to benefit from interest and dividend income generated from inter-corporate loans and investments although the contribution is expected to decline by the end of F2001 as inter-corporate loans from affiliates are repaid.

In the longer term, a slowdown in the Canadian economy could lead to a further decline in interest rates and approved ROEs after F2001, which would adversely affect the earnings growth outlook.

FINANCIAL PROFILE

Operating cash flows in F2000 fell due to the unbundling and transfer of certain ancillary businesses to an affiliate. The unbundling transaction generated $737 million in proceeds that were used as follows: (1) $306 million was loaned to parent Enbridge Inc., and generates about $21.5 million in interest income annually; (2) $233.7 million was paid out in a special dividend to Enbridge Inc.; and (3) the balance was used to repay maturing debt and for general corporate purposes including higher working capital needs related to the rising cost of natural gas inventories. Balance sheet leverage adjusted for hybrid securities issued during F2000 (preferred securities receive a 60% equity weighting and perpetual preferred shares a 70% equity weighting) fell to 60.7% from 62.3% the previous year.

Note that for regulatory purposes, the perpetual preferred shares are treated as debt equivalents. The inter-corporate preferred securities ($200 million issued during F1999) and investments ($415 million investment to an affiliate in F1999) are not part of rate base and have been structured to be neutral to the utility (i.e., the dividends received are at least 2X the interest expense associated with inter-corporate loan).

Interest coverage (fixed charges ratio) was relatively flat for F2000 despite the weather-related decline in EBIT, and materially benefited (almost 20 basis points) from substantial interest/dividend income on incorporate investments. Excluding the negative impact of warmer than normal weather, the fixed charges coverage ratio would have been about 2.2X versus 2X achieved.

For years ended September 30	2000	1999	1998	1997	1996	1995	1994
Net income (after pfd dividends)	117.3	106.3	90.8	134.2	140.8	97.8	121.3
Depreciation	176.8	214.8	196.8	169.7	134.0	119.2	105.1
Other non-cash adjustments	18.2	45.8	(15.8)	(6.2)	27.5	(6.0)	2.6
Operating Cash Flow	312.3	366.9					
LESS: Capital expenditures	233.0	356.1					
Cash flow before working capital changes							
LESS: Working capital changes							
Free Cash Flow before dividends							
LESS: Common dividends							
Free Cash Flow after dividends			(305.0)				
LESS: Other investments			37.2				
PLUS: Net debt financing (1)			391.0				
PLUS: Net pfd equity financing			(1.2)				
PLUS: Net common equity financing (2)			0.0				
Net Change in Cash Flows	114.9	(47.8)	47.6	94.8	(31.8)	(56.3)	(79.9)
Cash flow/Capital expenditures (times)	1.34	-	-	1.03	0.70	0.73	0.83
Cash flow/Adj. total debt (times) (3)	0.14	-	-	0.15	0.11	0.14	0.15
% Adj. debt in the capital structure (3)	60.7%	-	-	62.3%	70.7%	67.5%	68.2%
Fixed charges coverage (times)	1.99	-	-	1.98	1.97	2.46	2.42

(1) Effective 1998 includes short-term financing. (2) Includes contributed surplus. (3) Adjusted for equity treatment of hybrid

Outlook: Operating cash flows in F2001 are expected to decline and stabilize at lower than weather normalized historical levels following the transfer of retail products and services operations (lower depreciation expenses and a reduction in deferred tax credits). Cash flows should be sufficient to finance annual capital expenditures that are expected to remain in the $235 million range, but an increase in borrowing requirements is expected to finance sharply higher working capital changes, given that natural gas prices are significantly higher this winter than last winter. Inter-corporate loans from an affiliate will likely be repaid and the funds used along with higher short-term borrowings to address financing requirements during F2001. As a result of the unbundling of ancillary businesses (water heater rentals, retail products and services) and the decline in approved ROEs, DBRS expects certain key financial ratios, including cash flow/total debt and fixed charges coverage, to weaken and stabilize at levels below weather-normalized historical highs. Balance sheet leverage should remain relatively stable given the nature of the industry.

Operating Lines of Credit

Consumers' Gas has $290 million in committed lines of credit with a syndicate of twelve banks and another $300 million in uncommitted lines of credit, both of which are used to support a commercial paper program and for day-to-day working capital needs. The committed line agreement is a 364-day revolving facility that is renewable in October 2001. The Company is in the processing of securing additional committed lines of credit to fully support commercial paper borrowings.

Debt Maturity Schedule

	F2001	F2002	F2003	F2004	F2005
(As at September 30) ($ millions)	16.5	205			

The Consumers' Gas Company Ltd.

Balance Sheet
(\$ millions)

Assets:	As at September 30 2000	1999	1998	Liabilities & Equity:	As at September 30		1998
Cash + equivalents	0.0	0.3	51.2	S.T. + L.T.D. due 1yr			453.5
Accounts receivable	310.3	290.9	215.0	A/P + accr'ds			330.4
Materials + supplies	0.0	39.4	34.5	Current Liabilities			
Gas in storage	541.0	375.1	357.8	Def'd taxes + credits			
Other current assets	16.9	28.8	64.5	Long-term debt			
Current Assets			723.1	Debt equiv pfds			
Net fixed assets			3,094.0	Inter-corp debt			
Other assets			111.4	Inter-corp pfd sec			
Investments			0.0	Perpetual pfds			
				Shareholders' equity			
Total	4,367.8	4,507.6	3,928.5	Total	4,367.8	4,507.6	3,928.5

Ratio Analysis	*Industry Avg.**	For years ended September 30						
Liquidity Ratios	*Sep-00*	2000	1999	1998	1997	1996	1995	1994
Current ratio	*0.91*	0.86	0.80	0.92	0.55	0.60	0.62	0.80
Accumulated depreciation/Gross fixed assets	*28.0%*	28.7%	28.0%	26.5%	25.1%	24.7%	24.7%	24.4%
Cash flow/Total debt (1)	*0.13*	0.14	0.15	0.11	0.14	0.15	0.11	0.13
Cash flow /Adjusted total debt (1)(2)	*0.13*	0.14	0.15	0.11	0.14	0.15	0.11	0.13
Cash flow/Capital expenditures (1)	*1.09*	1.34	1.03	0.70	0.73	0.83	0.63	0.83
Cash flow-div's/Capital expenditures (1)(3)	*0.47*	-0.11	0.79	0.50	0.56	0.64	0.44	0.60
% Debt in capital structure	*62.4%*	57.9%	59.7%	70.7%	67.5%	68.2%	68.4%	68.1%
% Adjusted debt in capital structure (2)	*63.5%*	60.7%	62.3%	70.7%	67.5%	68.2%	68.4%	68.1%
Total hybrids + preferreds/Common equity	*10.0%*	22.1%	21.8%	0.0%	0.0%	0.0%	0.0%	0.0%
Average coupon on long-term debt	*8.75%*	8.40%	8.19%	8.22%	9.05%	9.47%	9.61%	9.64%
Deemed equity	*36%*	35%	35%	35%	35%	35%	35%	35%
Common dividend payout (3)	*126.7%*	285.8%	86.5%	86.0%	54.6%	48.6%	67.1%	52.3%
Coverage Ratios (4)								
EBIT interest coverage	*2.11*	2.23	2.15	2.11	2.64	2.60	2.00	2.54
EBITDA interest coverage	*3.05*	3.22	3.36	3.28	3.71	3.47	2.82	3.35
Fixed charges coverage	*1.95*	1.99	1.98	1.97	2.46	2.42	1.85	2.34
Earnings Quality/Operating Efficiency & Statistics								
Operating margin	*40.5%*	42.8%	37.7%	38.9%	43.7%	45.8%	40.2%	47.3%
Net margin (after pfd div's)	*15.5%*	14.6%	10.9%	10.0%	14.1%	16.1%	13.6%	17.4%
Return on avg. common equity	*10.8%*	8.9%	8.9%	8.8%	13.8%	15.9%	11.7%	15.4%
Approved ROE		9.73%	9.51%	10.30%	11.50%	11.88%	11.65%	11.60%
Degree day deficiency - % Normal		90.8%	85.2%	82.2%	100.2%	103.7%	94.8%	109.3%
Customers/Employee	*405*	846	418	370	352	343	327	318
Customer growth	*2.6%*	3.8%	3.6%	3.8%	4.1%	3.4%	3.7%	3.6%
Operating costs/Avg. customer (\$) (5)	*372.0*	282.1	389.2	377.4	378.7	346.0	324.5	281.4
Rate base (\$millions)		2,806.2	3,283.2	3,058.8	2,831.0	2,602.2	2,429.8	2,244.9
Rate base growth	*-0.5%*	-14.5%	7.3%	8.0%	8.8%	7.1%	8.2%	8.5%
Kilometres of pipeline		28,644	27,707	26,573	25,416	24,626	23,897	23,460
Rate base/Km of pipeline (\$000s)		97.97	118.50	115.11	111.39	105.67	101.68	95.69
Rate base/Throughput volumes (\$millions per bcf)		6.66	8.17	7.71	6.61	6.08	6.22	5.38

* DBRS Industry composite for Cdn. gas distributors. Values for average coupon, customers/employee, customer growth, operating costs/avg customer, and rate base growth is as at December 1999.

(1) Cash flows are after all preferred dividends.

(2) Preferred securities given 60% equity treatment, perpetual preferreds 70% equity treatment.

(3) Includes a special \$233.7 million dividend paid out in F2000.

(4) Before capitalized interest, AFUDC, debt amortizations. Includes the impact of intercorporate financings.

(5) Operating costs exclude municipal + property taxes.

Industry Study

Assessing Regulatory Risk in the Utilities Sector

MAY 2012

DBRS

Insight beyond the rating.

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Assessing Regulatory Risk in the Utilities Sector

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Executive Summary

The key business risk drivers in the utilities sector are characteristics of the regulatory framework in which the utility conducts its business. Different frameworks can lead to different degrees of regulatory risk associated with decisions made by the regulator. DBRS has reviewed ten major factors which can determine the degree of this regulatory risk. Adverse changes occurring within these factors could create earnings and cash flow volatility, potentially leading to negative rating actions.

Below are the ten key criteria reviewed and used by DBRS to determine the regulatory risk:

(1) **Deemed Equity:** Deemed Equity is the percentage of equity investment in the rate base on which a utility could earn a return. In general, the higher the Deemed Equity portion, the higher the earnings for a utility. In addition, utilities tend to maintain their actual capital structure in line with the regulatory capital structure. As such, the higher Deemed Equity set by the regulator, the more financial flexibility a utility can have.

(2) **Allowed Return (ROE) on Deemed Equity:** Allowed ROE is a measurement of regulated returns on the Deemed Equity portion of the rate base. The regulator sets an allowed ROE based on a utility's business risk level (which is assessed by the regulator) relative to a benchmark utility within the jurisdiction. In a supportive regulatory environment, utilities tend to achieve their actual ROE in line with the allowed ROE. In an unsupportive regulatory regime, utilities often generate lower actual ROE than the allowed ROE.

(3) **Fuel and Purchased Power (or Gas) Cost Recovery Certainty and the Timing of the Recovery:** Fuel and purchased energy cost (F&PE) recovery certainty and the timing of recovery are critical in assessment by DBRS of a regulatory system within a certain jurisdiction. DBRS looks at the following factors: (i) whether F&PE costs are fully passed through to the customers; (ii) how often a utility is allowed to adjust the F&PE costs in retail rates charged to customers; and (iii) if there is a mechanism within a jurisdiction, to allow utilities to make F&PE cost adjustments with no or minimal regulatory review. In addition, DBRS also focuses on the generation mix within a certain market. A high power cost market could have an impact on the utility's ability to recover the purchased power costs in a timely manner.

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

(5) **Capital Cost Recovery (CCR):** In assessing CCR, DBRS focuses on the likelihood of a utility's capital expenditures to be added to its rate base and the timing of such addition. In particular, DBRS looks at the following factors: (i) whether the capital expenditure is pre-approved by the regulator; (ii) whether the spending is allowed to be added to the rate base during the construction, or will only be added when the project is completed, (iii) the level of upfront capital spending required without regulatory approval; (iv) the degree of regulatory lag and uncertainty with respect to CCR; and (v) whether or not there is a reasonable mechanism to deal with cost overruns.

(6) **Political Interference:** Political interference refers to political risk that could occur within a jurisdiction. Political interference could be in the following forms: (i) influence on the regulator's ability to independently and impartially arrive at a decision; (ii) passing legislation to override a decision made by the regulator; and (iii) the regulator being elected instead of being appointed.

(7) **Retail Rate:** Retail rates refer to the rates (energy cost, transmission cost and distribution charges) a utility can charge its residential customers. This is important for the regulator to assess rate increase requests by utilities. By law, the regulator must allow a utility to earn a "just and reasonable return," but it also has to balance the interests of both a utility and its consumers. In a franchise area where customers pay relatively high retail rates or in a weak economic environment, the regulator may be reluctant to allow the utility to fully recover its excessive costs within a short period of time.

(8) **Stranded Costs:** Stranded costs occur when a utility already incurred costs (F&PE, operating cost or capital spending) and faces uncertainties as to when it can recover these costs. In some cases, stranded costs are written off if it is certain these costs cannot be recovered. DBRS looks at the following factors: (i) whether stranded costs exist and their magnitude; (ii) the likelihood of recovery of stranded costs; (iii) the frequency of writedowns; and (iv) the time it takes to recover these costs.

(9) **Rate Freeze:** A rate freeze refers to a fixed retail rate that can be charged to customers during a period of time (more than two years). During the rate-freeze period, utilities are exposed to increases in operating and energy costs. The longer the rate-freeze period or the more frequency a rate-freeze occurs within a jurisdiction, the higher the risk for the utility.

(10) **Market Structure (Deregulation):** Market structure refers to the electricity or gas market functions within the regulatory regime. DBRS particularly focuses on whether the market is deregulated and the degree to which the market has been deregulated. The strongest utilities will have fully-integrated operations (generation, transmission and distribution).

The following tables outline DBRS's approach to reviewing and ranking the ten criteria outlined above. This ranking of the criteria is based on a five-point scale (outstanding, excellent, very good, good or satisfactory).

Criteria 1: Deemed Equity

Definition

Deemed Equity is the percentage of equity investment in the rate base on which a utility could earn a return. In general, the higher the Deemed Equity portion, the higher the earnings for a utility. In addition, utilities tend to maintain their actual capital structure in line with the regulatory capital structure.

Score	Item	Definition
Outstanding	50%+	• Equity represents 50% or more of utility's rate base • The treatment of Deemed Equity is consistent historically
Excellent	45-50%	• Equity represents 45-50% of utility's capital structure • The treatment of Deemed Equity is consistent historically
Very Good	40-44.99%	• Equity represents 40-44.99% of utility's capital structure • The treatment of Deemed Equity has not been consistent historically
Good	35-39.99%	• Equity represents 35-39.99% of utility's capital structure • The treatment of Deemed Equity has not been consistent historically
Satisfactory	Below 35%	• Equity represents less than 35% of utility's capital structure • The treatment of Deemed Equity has not been consistent historically

Criteria 2: Allowed ROE

Definition

Allowed ROE is a measurement of returns on the Deemed Equity portion of the rate base. The regulator sets an allowed ROE based on a utility's business risk level (which is assessed by the regulator) relative to a benchmark utility within the jurisdiction. In a supportive regulatory environment, utilities' actual ROE are generally in line with the allowed ROE. In an unsupportive regulatory regime, utilities often generate lower actual ROE than the allowed ROE.

Score	Item	Definition
Outstanding	10%+	• Allowed ROE set at 10% • The regulatory treatment of allowed ROE has been consistent historically • There is no link to the Government bond rates
Excellent	9-10%	• Allowed ROE set at 9-10% • The regulatory treatment of allowed ROE has been consistent historically • There is no link to the Government bond rates
Very Good	8-8.99%	• Allowed ROE set at 8-8.99% • The regulatory treatment of allowed ROE has been consistent historically • There is no link to the Government bond yield
Good	7-7.99%	• Allowed ROE set at 7-7.99% or linked to the Government bond yield • The regulatory treatment of allowed ROE has NOT been consistent historically
Satisfactory	Below 7%	• Allowed ROE set below 7% or linked to the Government bond yield • The regulatory treatment of allowed ROE has NOT been consistent historically

Criteria 3: Energy Cost Recovery

Definition

Fuel and purchased energy cost (F&PE) recovery certainty and the timing of recovery are critical in DBRS's assessment of a regulatory system within a certain jurisdiction. DBRS looks at the following factors: (i) whether F&PE costs are fully passed through to the customers; (ii) how often a utility is allowed to adjust the F&PE costs in retail rates charged to customers; and (iii) if there is a mechanism within a jurisdiction to allow utilities to make F&PE cost adjustments with no or minimal regulatory review. In addition, DBRS also focuses on the generation mix within a certain market. A high power cost market could have an impact on the utility's ability to recover the purchased power costs in a timely manner.

Score	Item	Definition
Outstanding	Monthly	• F&PE costs are fully passed through • Adjustment is made on a monthly basis • There is an automatic adjustment mechanism • The jurisdiction is in a favourable generation mix market resulting in low power cost
Excellent	Quarterly	• F&PE costs are fully passed through • Adjustment is made on a quarterly basis • There is an automatic adjustment mechanism • The jurisdiction is in a favourable generation mix market resulting in low power cost
Very Good	Quarterly with regulatory review	• F&PE costs are fully passed through • Adjustment is made on a quarterly basis • F&PE cost deferrals are subject to some regulatory review • The jurisdiction is in a good generation mix market
Good	Annually with automatic adjustment	• F&PE costs are fully passed through or utilities having minimal exposure to the energy price volatility • Adjustment is made on an annual basis and is subject to minimal or some regulatory review • The jurisdiction is in an above-average power cost market
Satisfactory	Annually with no automatic adjustment mechanism	• F&PE costs are fully passed through or utilities having minimal exposure to the energy price volatility • Adjustment is made on an annual basis • F&PE cost deferrals are subject to regulatory review • The jurisdiction is in an above-average power cost market

Criteria 4: Cost of Service vs. Incentive Regulation Mechanism

Definition

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

Score	Item	Definition
Outstanding	COS	• COS regime allowing utilities to recover prudently and reasonably incurred operating costs • Capital expenditures are reviewed and approved by the regulator through an annual COS filing • There is a good mechanism for a utility to recover extraordinary operating costs
Excellent	IRM (three years or shorter)	• IRM regime with maximum three years between the COS years • Regulator sets a reasonable productivity factor X • There is a reasonable mechanism to consider incremental capital expenditures
Very Good	IRM (four-to-five-year framework)	• The IRM period is four to five years • Regulatory sets a reasonable productivity factor X • There is a reasonable mechanism to consider incremental capital expenditures
Good	IRM (six-to-ten-year framework)	• The IRM period is six to ten years • Regulatory sets a reasonable productivity factor X • There is a reasonable mechanism to consider incremental capital expenditures
Satisfactory	IRM (ten+ years)	• The IRM period is over ten years • Regulatory sets a reasonable productivity factor X • There is a reasonable mechanism to consider incremental capital expenditures

Criteria 5: Capital Cost Recovery

Definition

In assessing CCR, DBRS focuses on the likelihood of a utility's capital expenditures to be added to its rate base, along with the timing of such addition. In particular, DBRS looks at the following factors: (i) whether the capital expenditure is pre-approved by the regulator; (ii) whether the spending is allowed to be added to the rate base during the construction, or will only be added when the project is completed; (iii) the level of upfront capital spending required without regulatory approval; (iv) the degree of regulatory lag and uncertainty with respect to CCR; and (v) whether or not there is a reasonable mechanism to deal with cost overruns.

Score	Item	Definition
Outstanding	Pre-Approved (Construction Work-in-Progress into Rate Base)	• Pre-approved by regulator • Work-in-progress costs can be added to the rate base • There is a reasonable mechanism to deal with overrun costs
Excellent	Pre-Approved (Adding to Rate Base Upon Completion)	• Pre-approved by regulator • Capital costs are added to the rate base after completion of work • There is a reasonable mechanism to deal with costs overruns
Very Good	Modest upfront capital spending with minimal regulatory lag	• Capital expenditures are generally pre-approved by regulator, but there is some modest upfront capital spending before regulatory approval • Capital costs are added to the rate base after completion of work • There is a reasonable mechanism to deal with cost overruns
Good	Significant upfront capital spending with some regulatory lag	• There is significant upfront capital spending before regulatory approval • Capital costs are added to the rate base after completion of work • The recovery of capital expenditures is subject to some regulatory lag
Satisfactory	Significant recovery lag, and some risk of cost overruns	• Capital expenditures are generally not pre-approved by regulator • Capital costs are added to the rate base after completion of work • Significant regulatory lag with respect to the recovery of project capital expenditures • Risk of cost overruns being disallowed

Criteria 6: Political Interference

Definition

Political interference refers to political risk that could occur within a jurisdiction. Political interference could be in the following forms: (i) influence on the regulator's ability to independently and impartially arrive at a decision; (ii) passing legislation to override a decision made by the regulator; and (iii) the regulator being elected instead of being appointed.

Score	Item	Definition
Outstanding	AAA	• No government influence on the regulatory decision-making process • There has been no adverse legislation in the regulated utility sector • The regulator is appointed
Excellent	AA	• Low degree of government influence on the regulatory decision-making process • There has been no adverse legislation in the regulated utility sector • The regulator is appointed
Very Good	A	• Low degree of government influence on the regulatory decision-making process • There has been no adverse legislation in the regulated utility sector • The regulator is appointed or elected
Good	BBB	• Modest degree of government influence on the regulatory decision-making process • There has been no adverse legislation in the regulated utility sector • The regulator is appointed or elected
Satisfactory	BB	• High degree of government influence on the regulatory decision-making process • There has been some adverse legislation in the regulated utility sector • The regulator is appointed or elected

Criteria 7: Retail Rate

(Average Price for Residential Customers (monthly consumption of 1,000kwh)

Score	Item	Definition
Outstanding	Below 8 cents	• Consistently below 8 cents per 1,000 KWh • Strong economic environment
Excellent	8-10.99 cents	• Consistently in the 8-10.99 cents per 1,000 KWh range • Strong economic environment
Very Good	11-13.99 cents	• Consistently in the 11-13.99 cents per 1,000 KWh range • Very good economic environment
Good	14-16.99 cents	• Consistently in the 14-16.99 cents per 1,000 KWh range • Good economic environment
Satisfactory	17+ cents	• Consistently higher than 17 cents per 1,000 KWh • Good economic environment

Criteria 8: Stranded Cost Recovery

Definition

Stranded costs occur when a utility has already incurred costs (F&PE, operating cost or capital spending) and faces uncertainty as to when it can recover these costs. In some cases, stranded costs are written off if it is certain these costs cannot be recovered. DBRS looks at the following factors: (i) whether stranded costs exist and their magnitude; (ii) the likelihood of recovery of stranded costs; (iii) the frequency of writedowns; and (iv) the time it takes to recover these costs.

Score	Item	Definition
Outstanding	No Stranded Cost	• No stranded costs associated with legitimate or reasonable costs incurred by utilities
Excellent	Full Recovery	• Some stranded costs exist • Stranded costs are fully recovered in a timely manner • No historical stranded costs writedowns
Very Good	Occasional Writedowns	• Some stranded costs exist • Stranded costs are recovered but subject to some regulatory lag • Occasional writedowns
Good	Frequent Writedowns	• Some stranded costs exist • Stranded costs are sometimes recovered • Frequent writedowns • Takes considerable time to recover costs
Satisfactory	Frequent Significant Writedowns	• Significant stranded costs exist • Stranded costs are not fully recovered • Significant writedowns occur • Significant regulatory lag associated with the recovery

Criteria 9: Rate Freeze

Definition

A rate freeze refers to a fixed retail rate that is charged to customers during a period of time (more than two years). During the rate-freeze period, utilities are exposed to increases in operating and energy costs. The longer the rate-freeze period or the more frequency a rate-freeze occurs within a jurisdiction, the riskier for the utility.

Score	Item	Definition
Outstanding	Never	• Rates are never frozen
Excellent	Potential	• Rates have the potential to be frozen
Very Good	Occasional	• Rates are occasionally frozen • The frozen period is less than three years
Good	Frequently	• Rates are frequently frozen • The frozen period is less than three years
Satisfactory	Rate Freeze	• Rates are currently frozen • The frozen period is three years and longer

Criteria 10: Market Structure (Deregulation)

Definition

Market structure refers to the electricity or gas market functions within the regulatory regime. DBRS particularly focuses on whether the market is deregulated and to what degree the market has been deregulated. The strongest utilities will have fully-integrated operations (generation, transmission and distribution).

Score	Item	Definition
Outstanding	Fully Regulated	• The market is fully regulated • Fully integrated utilities
Excellent	–	–
Very Good	Partial Regulation	• The market is not fully regulated • Utilities are partially regulated • Good market structure, providing stability and low risk associated with purchased energy costs and counterparty risk
Good	–	–
Satisfactory	Fully Deregulated	• The market is fully deregulated • Market structure provides some risk with respect to purchased energy costs and counterparty risk

Insight beyond the rating.

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BOARD STAFF INTERROGATORY #4

INTERROGATORY

E - Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Ref: Ex. E2 /Tab 1/ Sch 2 / para 39 & 42

Enbridge in these paragraphs refers to the possibility of a credit rating downgrade and increased business risks.

Has the Company ever faced difficulties accessing capital? Please describe the circumstances and reasons surrounding any such instances.

In the face of the purported increased business risk to the Company, has any financial services sector agency declared publically that such increased risk will lead to potential difficulties attracting capital? Please provide copies of any such statements.

RESPONSE

In May 2003, Walter Schroeder, Founder and Chairman of DBRS, expressed concerns that Canadian Utilities earn lower ROEs suggesting that "Canadian utilities have less "safety margin" than U.S., and are vulnerable to a quick downgrade if something goes wrong" (please see Attachment 1).

In evidence provided in the 2004 Mainline Tolls and Tariff Application for TransCanada, Lackenbauer and Engen identified concerns with regulators appearing to be "… unwilling to recognize the increase in business risks that have occurred over the past several years as well as the fact that ROE's are at historic lows and do not present fair returns". Lackenbauer and Engen continued "S&P and DBRS are now making it clear that they share these concerns …" (please see Attachment 2)

In DBRS's Rating Report dated April 25, 2011 (please see Attachment 3), they identified low ROEs as a challenge in the rating process. Specifically DBRS identified "Low ROEs have a negative impact on earnings and cash flow, although an increasing rate

Witnesses: R. Fischer
M. Lister
D. Yaworski

base would partially mitigate this impact" (see attachment, filed at Exhibit I, Tab E2, Schedule 14.7).

In 2009, the Ontario Energy Board invited financial market practitioners / experts to offer their views on the assessment of the cost of capital for utilities in Ontario. Attached as Attachment 4 the transcription provided by Stephen Dafoe, the Director of Corporate Bond Research at Scotia Capital, as part of the Board's Cost of Capital Consultative (EB-2009-0084). Of particular note are the following passages from Mr. Dafoe's assessment:

> *"By mid-decade, many Canadian utility owners felt ROEs and equity capitalization levels were too low. Rate applications during this time tended to ask for higher capitalization and higher ROEs. However, in my written research during this period, I still expressed the view that provided the regulatory regimes remained stable and the risk of utilities of under-earning the allowed ROE was very, very low, financial performance was sufficient for the bond investor.*
>
> *Now, for what I think was a variety of reasons - things like evolving and improving industry best practices, technological changes that brought productivity gains and overall good management and other things - during this period the sector was able to consistently meet, and sometimes better, the allowed ROE targets. And this seemed to bear out the thesis that the risks in the sector were low enough to rationalize, if not entirely justify, the prevailing low ROEs at least from the perspective of the bond investor.*
>
> *And during this time, in my written work and presentations, I critiqued the rating agencies often for being overly cautious about financial ratios given industry's track record of stability.*
>
> *…*
>
> *As well, the utility industry is becoming more complex. Things like consumer consciousness, demanding energy conservation, rising requirements to connect green generation, the rising cost of electricity that's far from over, volatile natural gas costs, technology changes, such as the introduction of smart meters, the current severe demand recession that's going to reduce consumption in revenue but won't obviate the capital spending requirements to connect new loads. The list goes on and on.*
>
> *For the bond investor, all this means increased complexity, which means increased uncertainty over what the future might bring, which equals increased risk.*
>
> *The lower ROEs and higher complexity is coming at a time when many and probably all utilities are entering a generational cycle of capital spending on top of demand growth and technical change. And all this brings pressure on both business risks and utility credit ratios, particularly interest coverage and free cash flow.*
>
> *…*
>
> *First, I'd like to recall the March 6, 2003 Credit Watch experience. A major credit rating agency placed the whole Canadian utility sector on heightened risk of ratings downgrades. I'm pretty sure a few people in the room here remember that event quite well.*
>
> *My recollection is that the explanations given for the rating actions were not well understood by*

Witnesses: R. Fischer
M. Lister
D. Yaworski

the financial markets. In fact, I think some questioners on the conference call were politely skeptical of the reasoning offered. Others were more openly incredulous. And having had many conferences with fixed income investors about this at the time, I can say that the experience was viewed by many, and probably most, investors as a false alarm. And yet it still affected utility spreads for yearly a year, even though investors mostly disagreed.

This underlines the effect that ratings can and do have on corporate bond borrowers' cost of debt financing.

However, no one should assume that the rating agencies are indifferent to pressure on utility credit ratios. Time and again, in rating agencies' published reports on utilities, we see the phrase "credit metrics are weak for the ratings". To me, this is a caution to the reader that fair warning has been given. "Credit metrics are weak for the rating" means that the agencies can only have so much tolerance for the degree credit ratios weakening, or the duration of the time period where weak credit ratios are expected to continue.

Even if the agencies refuse to interject themselves in the regulatory process by refraining from directly commenting on ROEs, I would not infer that they are indifferent to how the sector deals with the cost of capital issue.

In this context, I have a further concern about how the rating agencies might react to persistent low ROEs and what might happen if they eventually downgrade. If ratings downgrades were made and investors actually agreed with the rating agencies' reasoning that credit risk in the sector was rising, in that case the spread valuation impact would, in my view, be likely more substantial and material and long lasting than was the case in Credit Watch of 2003.

…

So, to conclude, and sum up my presentation here, while rating agencies have made few explicit references to falling ROEs, their caution: Credit ratios are weak for the ratings, has been abundant and frequent. As a corporate bond analyst, I truly think that in the absence of some relief on the cost of capital, pressure on credit ratios coming at the same time as rising CAPEX requirements, and along with other complexities being introduced in the sector brings the risk of downgrades in the sector that is real.

Additionally, if downgrades do occur and if the rating agencies agree the sector is riskier, the cost of new debt financing could be materially higher than it's been for most of the past decade.

…

I understand that the OEB's focus in the consultation on the cost of capital is the application of the fair return standard as it applies to a utility's equity investors. That is as it should be. The core of the investigation should be an evidence-based assessment of what level of ROE, along with deemed capitalization, allows the utility's owner to achieve a return commensurate with investments of similar risk in today's capital markets. But the fair return standard also references the utility's ability to maintain its financial integrity and enables the utility to attract capital at a reasonable cost on reasonable terms and conditions. I view these aspects of the fair return standard as directly applicable to the utility's ongoing ability to raise funding in the bond market or other debt markets at optimal rates.

In hindsight, I think it's fair to say that in the middle part of this decade, utilities were able to take the Canadian public bond market for granted. It certainly offered abundant, long-term financing at a *favourable cost of borrowing. However, Canadian corporate bond market conditions have changed. Along with all investment markets globally, risk is being repriced at higher levels.*

To sum up, I think these corollary debt financing factors, while not central to answering the fair return on equity question, should be borne in mind by all participants in the broad cost of capital discussion."[1]

To date, the Company has not experienced difficulty in accessing capital.

[1]Consultation Process on Cost of Capital Review Stakeholder Conference, Ontario Energy Board, Case # EB-2009-0084, transcription of Stephen Dafoe, September 21, 2009.

Witnesses: R. Fischer
M. Lister
D. Yaworski

The Rating Process and the Cost of Capital for Utilities

Five Reasons why Canadian Utilities Have Lower Ratios, and Five Changes to Regulation Which Should be Introduced in Canada

May 2003

Regulation in Canada

- Regulation in Canada (non-telecommunication) has been heavily influenced by the National Energy Board (NEB)
- The NEB in Canada has the greatest resources available, and ranks among the most sophisticated regulators in Canada
- Provincial regulators have followed many of the NEB practices, including use of the formula – Canada + 325 or so basis points to set return on equity, and also a range of deemed equity near the 35% level
- Encouraging competition where returns are consistent with risk has been a practice followed in Canada and the U.S.
- Performance-based regulation has been followed where customers and the utilities often negotiated how to share the efficiencies and have avoided long arduous regulatory hearings
- Canadian regulators generally have been flexible, and unfavourable decisions can be reversed or altered when the extent of the problem is seen
- No Canadian utility has gone bankrupt due solely to the actions of the regulator
- This is not so in the U.S. with the California incident – a good example

Regulation in Canada (Cont'd…)

- PG+E went bankrupt when:
  - The state regulator forced sale of generation capacity
  - The regulator stopped PG+E from securing long-term power contracts
  - A flow-through of higher wholesale power costs was refused, and kept retail power rates rigid, resulting in the inevitable for PG+E
- Even debt levels of 30% would not have saved PG+E from bankruptcy
- Knowledge of the Regulator's policies, not quantitative ratios, were key to measuring the risk profile of PG+E
- DBRS looks at earnings past, present and future, the balance sheet and cash flows, past, present and future, and a wide range of subjective factors to arrive at a final rating. Regulation is an important component of this
- No one quantitative ratio is "magic," and the many qualitative and subjective factors are looked at in conjunction with quantitative data
- DBRS also stress tests the cash flow statement, looking at the effect different earnings, capital expenditure and dividend patterns have on future financial ratios – to get a worse case quantitative scenario – to complement the qualitative factors

Why Canadian Ratios for Utilities Are Lower Than Ratios in the U.S.

(1) Higher sensitivity to seasonality in Canada than the U.S.

- Canada has extreme temperatures which result in wide swings in accounts receivable and inventories
- Areas such as gas distribution tend to have wide swings in receivables and inventories between September to April
- The swing in debt levels can be 5%-10% between peak and trough

(2) Flow-through versus normalized tax accounting used in Canada

- Canadian regulators usually permit only flow-through accounting, versus the normalized taxation method often used in the U.S.
- Thus, U.S. utilities collect the corporate tax, and have coverage ratios up to 40-50 basis points better than Canadian utilities

Why Canadian Ratios for Utilities Are Lower Than Ratios in the U.S. (Cont'd…)

(3) Lower return on equity

- Canadian utilities earn lower return on equity, which is about 200 basis points below the U.S.
- In Canada, the formula method was initiated by the NEB, and adopted by most of the Provincial Regulators
- The formula generally allows a rate of return equal to 325 basis points over Canada bonds, with some limits on how much returns may change in any one given year
- The lower return on equity reduces interest coverage in Canada by about 20 basis points

Why Canadian Ratios for Utilities Are Lower Than Ratios in the U.S. (Cont'd…)

(4) Lower deemed equity in the capital structure in Canada

- Canadian utilities are generally allowed lower deemed equity to the degree of 5%-10%
- A 10% lower debt proportion can improve interest cost coverage by 50 basis points so this can cause significant savings in interest coverage
- Typically in Canada regulators often allow deemed equity of 30%-35%
- Utilities can partly neutralize this disadvantage to a degree by issuing hybrid capital known as super subordinate debt – which is not as good as pure equity
- If four conditions are met, DBRS will give a high weighting to hybrid securities
  - How subordinated are the instrument securities?
  - Do the securities have a maturity date?
  - Does default occur if the interest payment is not made?
  - Is the intent of the Company to treat the instrument as equity?
- Long-term super-subordinate debt 30 years + which receives good equity treatment by DBRS (which means interest payments also will have to be deferred) represents a cheap way of issuing equity, and may partly but not fully, neutralize the lower deemed equity allowed

Why Canadian Ratios for Utilities Are Lower Than Ratios in the U.S. (Cont'd…)

(5) Higher interest rates in Canada than the U.S.

- Interest rates were 100-200 basis points higher in Canada than the U.S. through much of the 1990s
- The higher interest rates in Canada had a downward effect on key coverage ratios, and much of this debt is still outstanding

Conclusion

- Quantitative ratios in Canada automatically have downward biases
- Our colder more extreme weather automatically raises debt proportions at the peak of the cycle because of inventory/receivable peaks and troughs
- The debt levels of Canadian utilities may swing, depending on the date chosen, due to seasonal factors

1) Flow-through tax accounting used in Canada costs Canadian utilities approximately 40 basis points on coverage
2) The 200 basis point lower allowed return on equity costs Canadian utilities 15-20 basis points on coverage

Why Canadian Ratios for Utilities Are Lower Than Ratios in the U.S. (Cont'd…)

Conclusion Cont'd…

3) The 5%-10% lower deemed equity of Canadian utilities can cost 50 basis points for EBIT coverage ratios

4) The 1%-2% higher interest rates which prevailed in Canada through most of the 1980s and 1990s cost Canadian utilities about 20 basis points

- Thus, Canada's climate, and the nature of Canadian regulation cost Canadian utilities about 130 basis points on average relative to the U.S.
- About 110 basis points of the 130 basis point difference is caused by regulators

5) Where all five variables discussed prevail at the same time (Case 5) the difference in interest coverage is 3.15 times versus 1.54 times, assuming Canada has (a) Deemed equity of 30% versus 40% in the U.S. (b) Return on equity of 12% in the U.S. and 10% in Canada (c) Income tax rates at 43%

The Need for Change in Standards by Canadian Regulators: Reasons for Change

(1) Different standards used between Canada and the U.S. have an immense effect on differences in coverage and other financial ratios which are important in credit ratings. On the whole, in our opinion Canadian regulators should give greater consideration to the effects that their actions have on the credit rating

(2) Competition is growing, raising risk and justifying higher rates of return

Examples:

- Alliance Pipeline provides competition for TransCanada Pipelines
- Restructuring of electricity in Alberta makes the area more competitive

The Need for Change in Standards by Canadian Regulators (Cont'd…)

(3) Regulators make returns in Canada more consistent with the U.S.

- TransCanada's 9.79% return on equity on 33% equity versus PGT's 12% on 35%
- Foothills eastern leg 9.79% on 30% versus Northern Border 12% on 35%
- TransCanada's Mainline 9.79% on 33% versus Great Lakes 13.25% on 44%
- Alliance Pipeline Canada 11.3% on 30% versus Alliance Pipeline U.S. 10.7% on 30%
- Maritime Northeast Pipeline Canada 13% on 25% versus Maritime NE Pipeline U.S. 14% on 25%
- Why is there such a different return between TransCanada versus Great Lakes or Foothills versus Northern Border?

(4) Provide more consistent standards

- A 30% deemed equity gets the same return on equity as a 35% or 40% deemed equity
- The lower the equity component, the higher the risk – so this is inconsistent reasoning

(5) Less of a safety margin in financial ratios if things go wrong in Canada

Positive Factors with Canadian Regulators

(1) Provincial regulation is quite consistent with NEB regulation. Policies usually do not clash

(2) Less turf wars between federal and provincial regulators

(3) (a) Canadian regulators will work with utilities to help them overcome problems. Example: The TransCanada take or pay gas recovery – over ten years

(b) Contrast this with the California regulator and PG&E experience

Effect of Canadian Style Regulation on Ratings

- DBRS has given Canadian regulation positive marks for consistency and stability (on the downside), and has considered this in the ratings (a subjective factor)
- However, Canadian utilities have less "safety margin" than U.S., and are vulnerable to a quick downgrade if something goes wrong
- There is a significant difference in financial ratio strength between Canadian and U.S. utilities

General Changes in Regulation That DBRS Would Like to See

1. Movement to performance-based regulation, where the customers and the utility work out returns and rewards, and regulatory hearings are reduced
2. Increase the allowed return on equity in order to make it more consistent with U.S. returns
3. Increase the deemed equity component to 35%-40% ranges

Regulation Comparison of OFGEM vs. FERC vs. NEB

Factor	OFGEM (U.K.)	FERC (U.S.)	NEB (Canada)
Regime	Rate cap	Cost-plus	Cost-plus
Philosophy/Objectives	The main objective is to protect the consumer and neutralize monopoly conditions in distribution and transmission. This includes not only establishing rates of return, but also monitoring quality of service, adequacy of capex to satisfy future demand, and measures of efficiency to determine future rates. The regulator is sophisticated, transparent, and has a good understanding of the rating process.	Although FERC historically employed a "laissez faire" approach to company regulation when compared to OFGEM and NEB, recent market events have prompted it to become a more active force in the marketplace. However, in general the rates of return better balance protection to the consumer and returns to the utility. The returns allowed by FERC can be 200 basis points higher than in Canada. Despite this, FERC often has to contend with lawsuits from utilities challenging its decisions. FERC is knowledgeable about the importance of ratings to a utility.	The NEB falls in between OFGEM and FERC in rate of return philosophy. It allows negotiated settlements between utilities and shipper, which makes possible performance-based regulation in Canada. Setting returns high enough to ensure investment-grade ratings is one of the principles followed by OFGEM and FERC. However, the NEB's policies have not strongly considered capital market access for utilities, and the NEB is the least concerned about how credit ratings affect capital access of utilities.

Regulation Comparison of OFGEM vs. FERC vs. NEB (Cont'd…)

Factor	OFGEM (U.K.)	FERC (U.S.)	NEB (Canada)
Consistency	One regulator prevails in the U.K. for all matters relating to onshore downstream natural gas and electricity (offshore and upstream are not regulated by OFGEM). This results in consistent decisions and only one body to conduct hearings.	Individual states have jurisdiction over matters relating to retail gas and electricity, while FERC has jurisdiction over inter-state movements. The result is inconsistency between states, and high costs preparing for many rate hearings.	As in the U.S., there can be inconsistency since the ten provinces and the federal NEB have jurisdiction. (The NEB has jurisdiction for inter-provincial movements of energy) However, practice shows that the provincial regulators work consistently with federal regulators.

Regulation Comparison of OFGEM vs. FERC vs. NEB (Cont'd…)

Factor	OFGEM (U.K.)	FERC (U.S.)	NEB (Canada)
Methodology	Cost of debt is calculated using risk-free rate of return and risk factor related to corporate risk. Cost of equity is calculated using a beta coefficient calculation to arrive at average cost of equity, and finally a weighted-average cost of capital.	Cost of equity calculation is used to arrive at weighted pre-tax cost of capital. Cost of equity return is equal to dividend yield plus growth factor to establish final return on equity. Final allowed return on regulatory assets is a composite cost of capital multiplied by regulatory assets.	Average risk-free return is used, plus a spread to allow for risk. The risk-free return is calculated using the three-year average yield of long-term Canada bond. The risk adjustment is calculated at 325 basis points over forecast 10-year Canada bond yields, with year-over-year adjustments capturing 75% of the movement in interest rates.

Regulation Comparison of OFGEM vs. FERC vs. NEB (Cont'd…)

Factor	OFGEM (U.K.)	FERC (U.S.)	NEB (Canada)
Profitability	Resulting returns on regulatory assets in the real 6.25%-6.50% range are low relative to alternative investments. The regulator subjected companies to sharp rate cuts effective April 1, 2000. Then annual rate changes restricted to RPI (Inflation) minus 1.5%-3%. Finally, cost saving benefits are expected to revert to the consumer in 2005, negatively affecting long-term profitability further. In 1998, the U.K. government also a levied surprise windfall profits tax on most utilities.	FERC had an initial conflict when gas and electricity divisions were merged at the FERC level. Returns in the electricity area were 100 basis points higher than what was allowed in the pipeline area. FERC resolved the situation by allowing higher returns for the pipelines, the company's proxy for calculating returns. The six proxy companies used in gas pipelines are now down to three companies due to mergers.	Use of average return on Canadian securities resulted in low returns (below 10% return on a deemed common equity). The allowed return is about 200 basis points below the U.S. utilities.

Regulation Comparison of OFGEM vs. FERC vs. NEB (Cont'd…)

Factor	OFGEM (U.K.)	FERC (U.S.)	NEB (Canada)
Intensity	Regulator watches and controls (with open transparency) most aspects of regulation in a hands-on procedure.	A "laissez-faire" procedure, once the rules have been set.	In between the two regulators. It does not control as intensely as OFGEM.
Lawsuits against regulatory decisions	Lawsuits are rare.	Lawsuits are common. Litigation after a regulatory decision happens quite often.	Lawsuits are rare, but could become more prevalent if there is no change.

Regulation Comparison of OFGEM vs. FERC vs. NEB (Cont'd…)

Factor	OFGEM (U.K.)	FERC (U.S.)	NEB (Canada)
Excess profits and cost savings	The decision to levy a windfall profit tax in 1998 was political, not regulator induced. The cost savings are expected to accrue to the customer after 2005, restricting future growth in profitability.	Regulation allows excess profits beyond allowed returns to accrue to the company. Once the returns have been set, (if through efficiency the company does better) the Company can keep the excess. Under performance-based regulation, the company and customers may negotiate how to share savings.	Profits remain with the company until the next rate hearing. Under performance-based regulation, the NEB has generally approved all agreements negotiated between pipelines and customers.

Examples of Effects of Coverage Ratios

Example:		
Assets	Liabilities + Equity	
1000	Debt	700
	Equity	300
	Total	1,000

Case 1

Effects of 12% return on equity in the U.S. versus 10% returns in Canada, all other things being equal

	Canada	U.S.
Income		
300 x 10%	30	
300 x 12%		36
Taxes (43%)	23	27
Total EBT	53	63
Interest (based on Canadian interest)	56	56
EBIT	109	119
Interest coverage	$\frac{109}{56} = 1.95$	$\frac{119}{56} = 2.13$

- The 200 higher return on equity gives U.S. entities 18 basis points higher interest coverage
- Interest and taxes were deemed to be the same (Canada, U.S.) to show the effect of return on equity only

Examples of Effects of Coverage Ratios (Cont'd…)

Case 2

Illustrate a higher 40% deemed equity versus 30% in Canada. Return on equity of 10% is used in both countries to highlight deemed equity effect

	Canada	U.S.
Income		
300 x 10%	30	
400 x 10%		40
Taxes (43%)	23	30
EBT	53	70
Interest (8% interest rate)	56	48
EBIT	109	118
Interest coverage	1.95	2.46

- Coverage differential is 51 basis points in the example in favour of the U.S.
- This is a major reason why interest coverage between the U.S. and Canada is so big

Examples of Effects of Coverage Ratios (Cont'd…

Case 3

The U.S. uses normalized taxation, versus the flow-through method used in Canada. Assume that all the tax can be tax sheltered

	Canada	U.S.
Income	30	30
Taxes (43%)	0	23
EBT	30	53
Interest	56	56
EBIT	86	109
EBIT coverage	1.53	1.95

- Taxation, with a full tax shelter results in 42 basis points difference
- If the tax shelter, due to capital cost allowances exceeding depreciation was 50%, the difference between Canada and the U.S. would be 21 basis points on the coverage ratio, but utilities can often tax shelter most income in the early years of expansion

Examples of Effects of Coverage Ratios (Cont'd…

Case 4

Higher interest rates in Canada versus the U.S. by 1.5%

Assume 70/30 Debt to Equity

	Canada	U.S.
Income	30	30
Tax	23	23
EBT	53	53
Interest		
700 x 8% - Canada	56	
700 x 6.5% - U.S.		46
EBIT	109	99
Interest coverage	1.95	2.15

- Lower interest rates in the U.S. makes a difference of 20 basis points in coverage
- While interest rates in Canada were lower in the 1990s then the U.S. – the long-term debt issued would take at least ten years to neutralize the interest rate differential

Examples of Effects of Coverage Ratios (Cont'd…)

Case 5

Coverage – U.S. and Canada combining all four variables

	Canada	U.S.
Earnings 300 x 10 - Canada	30	
Earnings 400 x 12 – U.S.		48
Income tax	0	36 *
EBT	30	84
Interest		
Canadian 700 x 8%	56	
U.S. 600 x 6.50%		39
EBIT	86	123
EBIT coverage	1.54	3.15

* In the U.S., assumption is made that all tax is sheltered.

- When all four variables are put together the difference in interest coverage is 161 basis points
- Of the four variables, three variables are directly related to actions of the regulator, including: (1) Return on equity, (2) Capital ratios, and (3) taxation methods

Summary

Differential in interest coverage U.S. higher than Canada due to:

Higher return on equity	0.18
Higher equity base	0.30
Normalized taxation with 100% tax shelter	0.42
Lower interest rates	0.20
Interest rate differential	1.10

- Interest coverage differential between U.S. and Canada is 1.10%
- If all factors are combined at the same time, the interest rate differential becomes 1.61%
- This differential gives Canadian utilities less of a "safety" margin should anything go wrong, because their ratios are much weaker

investments away from regulated operations into more attractive opportunities on a risk/reward basis.

If S&P follows through with a downgrade of TransCanada in the absence of any evidence of improvement in its credit metrics on the regulated companies, then all that would have to happen is for DBRS to conclude no improvement is forthcoming and follow suit. In that circumstance, TCPL and TransCanada Corporation would definitely have their access to capital markets impaired. Costs would increase (and the corresponding value of the outstanding debt would decrease), the amounts available and the debt term to maturity would decrease as well.

In TransCanada's case, several major institutional investors would sell their debt holdings because they would be significantly overweighted in the BBB rating category. Generally, institutional investors maintain investment guidelines which, among other things, restrict the amount of BBB debt they can hold. For the most part, such guidelines only allow a modest amount of BBB debt holdings. As a result, downgrading A rated debt to BBB levels often requires asset sales to comply with applicable investment guidelines. This would further exacerbate the problem. Since TCPL debt is so widely held, it would necessitate significant sales by such investors.

Q5. Why do you suggest that DBRS might be inclined to "follow suit" in the event of an S&P downgrade?

A5. It is important to realize that DBRS is also concerned about Canadian regulatory trends and their impact on credit quality erosion. In May 2003, Mr. Walter Schroeder, President of DBRS, addressed the CAMPUT conference in Banff and made several key points in his verbal and slide presentation. The heading on one section of his slides was **"The Need for Change in Standards by Canadian Regulators."** In his presentation, he questioned why ROEs and common equity ratios for utility companies in Canada are lower than in the U.S. He observed that Canadian utilities have less "safety margin" than U.S. utilities and are vulnerable to quick downgrades if something goes wrong. He also noted that there is a significant difference in financial ratio strength between Canadian and U.S. utilities and urged Canadian regulators to give greater consideration to the effects that their actions have on credit ratings.

In addition to the points which were in his slide presentation, he also added two key observations in his verbal remarks: (1) debt markets are effectively global markets now and must be looked at accordingly; and (2) utility companies should not be rated below the A category.

The relevance of Mr. Schroeder's presentation should be obvious. The S&P action cannot be viewed as unilateral or exceptional. The same issues concern DBRS and quick action there may occur without any additional warning in the absence of measures taken to improve the credit worthiness of Canadian utility companies. It is no exaggeration to say that putting TransCanada into the BBB category would be playing with fire. It would also be completely unfair to investors in the company whose risk adjusted returns would decrease if TransCanada were put into the BBB category.

Q6. Are you concerned to the same degree as the rating agencies?

A6. Yes. We are very concerned that Canadian regulators appear unwilling to fully recognize the increases in business risks that have occurred over the past several years as well as the fact that ROEs are at historic lows and do not represent fair returns.

S&P and DBRS are now making it clear that they share these concerns and are reconfirming the reality that the financial markets are global, not domestic. These are the same views that were set forth clearly in the RH-4-2001 proceedings but the Board remained unpersuaded.

To the extent that the Mainline traded on a stand-alone basis today, it would be a BBB credit, at the very least by S&P. Cross subsidization of Mainline credit is clearly occurring at the consolidated level by TCPL.

Rating Report
Report Date:
April 25, 2011

Previous Report
January 8, 2010

Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. The Company also distributes natural gas to approximately 15,000 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly-owned subsidiary of Enbridge Inc. (rated A (low)).

CP Limit: $700 million

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Ratings Update

DBRS has today confirmed the Unsecured Debentures & Medium-Term Notes, Commercial Paper, and Cumulative & Cumulative Redeemable Convertible Preferred Share ratings of Enbridge Gas Distribution Inc. (EGD or the Company) at "A", R-1 (low) and Pfd-2 (low), respectively, all with Stable trends based on EGD's low business risk operations, stable regulatory environment, strong franchise area and stable financial profile. The regulatory environment remains reasonable and stable, allowing the Company to recover its operating expenses and capital expenditures in a timely fashion. The ratings also reflect the low allowed ROE under which the Company must operate until 2012.

EGD currently benefits from productivity enhancements and incremental revenues under a 2008 Ontario Energy Board (OEB) approved incentive regulation (IR) framework (from 2008 to 2012). While a subsequent OEB general cost of capital decision provides for an initial ROE of 9.75% to be incorporated into a utility's 2010 Cost of Service Application, EGD's ROE of 8.39% will remain unchanged throughout the IR period. In May 2010, the OEB issued a decision that the new ROE could not be used to calculate earnings sharing with ratepayers. The Company's appeal of that decision was heard by the Ontario Divisional court in January 2011, with a decision pending. The ROE increase will likely be positive for EGD when the IR is renewed in 2013. (Continued on page 2.)

Rating Considerations

Strengths

(1) Low business risk operations with a stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics
(4) Price competitiveness of natural gas

Challenges

(1) Weather-related volume risk
(2) Significant seasonal liquidity requirements
(3) Moderate cash flow deficits due to increased capital expenditures
(4) Low allowed ROE

Financial Information

Enbridge Gas Distribution Inc.	For the 12 months ended				
	Dec. 10	Dec. 09	Dec. 08	Dec. 07	Dec. 06
EBIT interest coverage	2.4	2.6	2.5	2.2	1.8
Total debt/capital (incl intercompany loan)	54.6%	53.5%	57.9%	56.1%	59.8%
Cash flow/adjusted total debt (1)	17.5%	19.3%	15.3%	14.5%	9.1%
Cash flow/capital expenditures (times)	1.3	1.4	1.2	1.1	0.7
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.74%
Net income before extra items	212	240	217	190	127
Operating cash flow (CAD millions)	484	519	490	418	282

(1) Includes note receivable from parent company and investment in affiliate company

Ratings Update (Continued from page 1.)

EGD's gas distribution margin declined modestly in 2010 by 2.9% but had increased year-over-year from F2006 through F2009 due to customer growth, favourable changes in customer mix and higher distribution rates as a result of the application to the IR formula approved by the OEB. In 2010, warmer weather was the primary driver of the modestly lower earnings when compared to 2009.

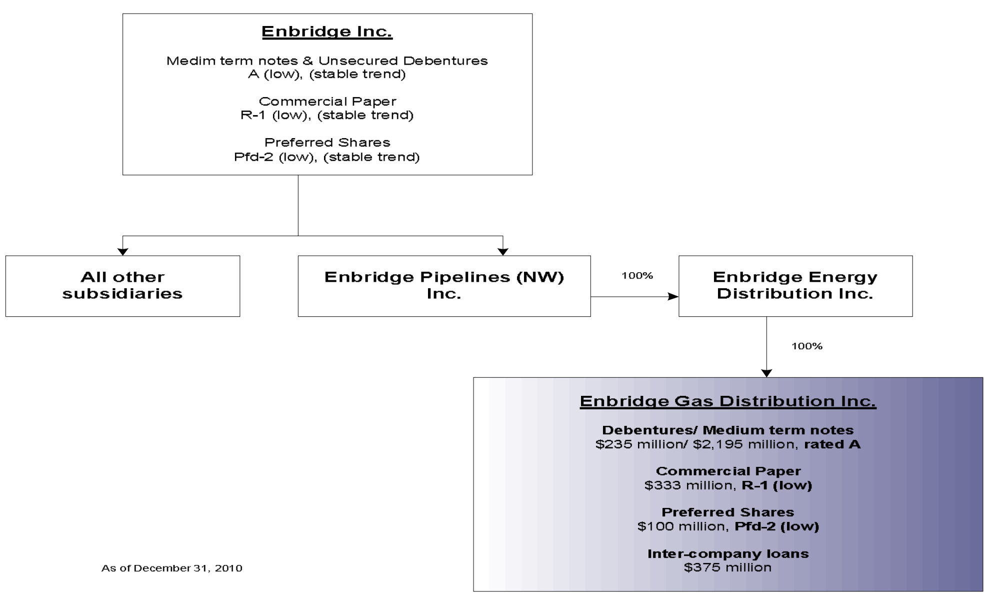
Customer growth however continues to be offset by lower average annual consumption. While the risk of fuel switching remains when natural gas prices are high (currently relatively low), natural gas is the predominant fuel of choice in the residential heating market in EGD's franchise area. Furthermore, natural gas has continued to provide price advantages over its primary competitors – domestic fuel oil and electricity.

For 2011, capital expenditures are expected to be approximately $500 million, having averaged $385 million annually in recent years, as the Company continues to invest in network expansion and upgrades to support customer growth, including lateral connections to new power generating facilities. Growth capex, which represents approximately 30% of capex, is expected to include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives.

As a portion of capital expenditures are financed through short-term debt and later refinanced with long-term debt, continued access to the short- and long-term capital markets is important for EGD. DBRS believes the Company's financing of these capital projects will be done in a manner that ensures it maintains stable credit metrics going forward. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain the stability of its credit profile and manage the regulatory approved capital structure.

The Company has very large and volatile seasonal liquidity requirements and usage of its credit facility remains high in the third and fourth quarter of the year as gas storage increases for the winter months. DBRS views the Company's current liquidity as adequate given the current low price gas environment, noting that a combination of cold weather and high gas prices could exhaust EGD's available liquidity.

Simplified Organizational Chart



DBRS

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Rating Considerations Details

Strengths

(1) EGD's low risk business operations continue to generate reasonably stable operating cash flows, while operating in a stable regulatory environment where the Company has the opportunity to recover its operating expenses and capital expenditures in a timely manner, and is allowed to earn a reasonable return on its investments. The Company has limited exposure to commodity price risk as its gas purchase costs are passed on to customers through quarterly rate adjustments. Furthermore, the long-term IR framework provides incentives for improved efficiency and long-term regulatory stability.

(2) EGD is the largest regulated natural gas utility in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. Modest and continued growth in its customer base will allow the Company to continue to generate strong earnings and cash flows.

(3) EGD maintains a reasonable balance sheet and credit metrics, reflecting: (a) total debt-to-capital ratio of 55%; (b) EBIT interest coverage ratio of 2.4 times; and (c) cash flow-to-debt ratio of 17.5%. The variability in cash flows and credit metrics year-over-year has been largely due to the impact of weather, seasonality of the gas distribution business and natural gas prices. The Company's credit metrics remain adequate for the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 36%.

(4) Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area and maintains both a price and environmental advantage relative to its primary competition, domestic fuel oil and electricity.

Challenges

(1) Weather remains the most significant risk, as forecast volumes, which are based on the normalized weather, are built into the Company's base rates, while actual usage varies with weather. Therefore, colder than normal weather would generally result in higher earnings compared to periods of warmer than normal weather. The years 2007 through 2009 were colder than normal and resulted in higher earnings for EGD when compared with 2010 which was warmer than normal.

(2) The Company has very large and volatile seasonal liquidity requirements, which has strained its available liquidity in the past. The Company's usage of its credit facility remains high in the third and fourth quarter of the year as gas storage increases for the winter months. As such, favourable access to the short- and long-term capital market remains important.

(3) Free cash flow deficits are expected to be modest over the medium term, mainly attributable to the Company's capital expenditures associated with unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives. EGD is expected to finance these deficits through debt issuances and management of dividend payments to (or equity injections from) the parent, so as to maintain the debt-to-capital ratio within the regulatory approved level of 64%.

(4) The IR framework has set a low base level for EGD's allowed ROE at 8.39% until year-end 2012. Thus, while the Company has the opportunity to earn higher returns, any upside is capped by the nature of the IR mechanism. Low ROEs have a negative impact on earnings and cash flow, although an increasing rate base would partially mitigate this impact.

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Earnings and Outlook

For the 12 months ended					
(CAD millions)	Dec. 10	Dec. 09	Dec. 08	Dec. 07	Dec. 06
Net gas distribution revenue	605	576	506	485	377
Gas transportation service revenue	390	449	505	500	493
Gas distribution margin	995	1,025	1,011	985	870
Other revenue	108	108	94	81	59
Total revenue	1,103	1,133	1,105	1,066	928
EBITDA (incl. income from affiliates)	729	761	746	707	586
EBIT (incl. income from affiliates)	459	507	507	479	373
Gross interest expense	189	195	206	214	207
Net income before extra. Items	212	240	217	190	127
Extraordinary items	(19)	(19)	(6)	0	0
Preferred dividends	(2)	(3)	(5)	(5)	(5)
Total	191	218	207	185	122
Return on equity	11.5%	12.9%	12.0%	11.2%	7.9%
EBIT margin	35.9%	39.2%	40.3%	39.0%	33.4%

Summary

- EGD's EBIT and EBITDA have remained stable over the past four years, and remained strong in 2010 primarily due to higher customer additions, favourable changes in customer mix and higher distribution charges, offset by warmer weather.
- EGD is expected to share excess earnings with customers under the current IR terms. The earnings sharing formula allows for earnings in excess of the annual adjusted ROE plus 100 basis points (bps) to be shared 50/50 with ratepayers. The Company's proportional estimate of earnings sharing was $19 million for 2010, subject to OEB approval in 2011.
- Transportation revenue has remained generally stable and represents 40% to 50% of the Company's gas distribution margins. EGD continues to monitor and take measures to mitigate potential weakness in the financial position of its large industrial customers.
- Interest expense has continued to decline modestly over the past few years with lower short-term borrowings as a result of lower gas prices.

Outlook

- The Company's earnings, under normal weather conditions, should grow moderately over the medium term, driven primarily by customer and economic growth in the Company's franchise areas and the continued competitiveness of natural gas. The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Though EGD's request to the OEB for approval to use the new base level ROE of approximately 9.85% to determine the annual earnings sharing with customers for 2010 and the remainder of the IR was denied, the Company anticipates applying the then-current ROE to determine rates after the conclusion of the IR terms, effective for the rate year beginning 2013. EGD has appealed the OEB ruling, with a decision pending.

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Financial Profile

Statement of Cash Flow	Dec 31	Dec 31	Dec 31	Dec 31	Dec 31
(CAD millions)	2010	2009	2008	2007	2006
Net income (after pfd dividends)	210	237	212	185	122
Depreciation & amortization	270	254	239	228	213
Non-cash charges & deferred income taxes	4	29	39	5	(53)
Cash Flow From Operations	484	519	490	418	282
Capital expenditures	(365)	(370)	(411)	(385)	(393)
Dividends to the parent	(208)	(181)	(158)	(65)	(175)
Free Cash Flow Before W/C Changes	(89)	(32)	(80)	(32)	(285)
Working capital changes	31	467	(125)	133	181
Net Free Cash Flow	(58)	436	(205)	101	(104)
Acquisitions/Divestitures	0	0	0	0	0
Other/adjustment	0	(14)	5	(12)	(30)
Cash flow before financing	(58)	422	(200)	89	(135)
Net change in debt financing	69	(470)	261	(167)	136
Net change in pfd equity financing	0	0	0	0	0
Net change in common equity	0	0	0	88	0
Other/adjustment	(16)	(21)			
Net change in cash flows	(5)	(68)	60	10	1

Key Figures and Ratios	Dec 31 2010	Dec 31 2009	Dec 31 2008	Dec 31 2007	Dec 31 2006
ST debt (millions)	500	677	1,026	826	831
LT debt (millions)	2,267	2,015	2,167	2,064	2,258
Inter-company debt ($ millions)	375	375	375	375	375
Total debt/capital (incl intercompany loan)	54.6%	53.5%	57.9%	56.1%	59.8%
Total debt/capital (excl. intercompany loan)	59.2%	58.1%	62.3%	60.8%	64.7%
EBIT interest coverage (incl. intercompany loan) (1)	2.4	2.6	2.5	2.2	1.8
EBIT interest coverage (excl. intercompany loan)	2.4	2.6	2.5	2.2	1.7
Cash flow/total adjusted debt (1)	17.5%	19.3%	15.3%	14.5%	9.1%
Cash flow/adjusted long-term debt (1)	20.0%	24.0%	21.6%	17.9%	12.5%
Dividend payout ratio	99.1%	76.6%	75.1%	36.9%	141.1%
Fixed charges coverage (times)	2.4	2.5	2.4	2.2	1.7

(1) Includes note receivable from parent company and investment in affiliate company.

Summary

- Cash flow from operations was sufficient to cover both dividends paid to the parent and estimated maintenance capital expenditures in 2009 and 2010. Credit metrics are expected to come under modest pressure from increasing capital expenditures.
- The Company's credit metrics remain consistent with the current rating category.
- EGD has a targeted dividend payment of 90% to 100% subject to maintaining a capital structure in line with regulatory levels.

Outlook

- DBRS expects EGD to generate modest free cash flow deficits due to capital expenditures in the medium term, which will be funded with a combination of debt and dividend management in order to maintain its credit metrics and manage the regulated approved capital structure.
- Capital expenditures (including growth) in 2011 are expected to increase to $500 million from current levels as the Company continues to invest in maintenance, network expansion and upgrades to support customer growth. Capital projects for 2011 include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives.
    - Deregulation of new natural gas storage has created a growth opportunity for EGD, as a result the Company expanded its storage capacity in 2010 by 8% and sold unregulated storage services into the storage market.

- EGD continues to have strong access to the short- and long-term capital markets. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain the stability of its credit metrics.

Long-Term Debt Maturities and Liquidity

Long Term debt (CAD millions)	**Average Coupon**	**Maturity**	**Dec. 31, 2010**	**Dec. 31, 2009**
Debentures	10.46%	2011-2024	235	385
Medium-term notes	5.54%	2011-2036	2,195	1,795
Other			6	12
Total long-term debt			2,436	2,192
Loans from affiliate			375	375

Debt Maturity schedule	Less than 1 year	1-3 years	3-5 years	Thereafter	Total
As at Dec. 31, 2010 (CAD millions)	150	0	400	1,880	2,430

- EGD's debt repayment schedule remains manageable, with only $150 million maturing within the next three years.
- As of December 31, 2010, EGD had issued $2,195 million of medium-term notes (MTNs) at an average coupon rate of 5.54%.
- EGD is subject to an EBIT interest covenant in order to issue additional indebtedness. EBIT for any 12 consecutive months out of the previous 23 months must be at least two times its annual pro forma interest requirements for all debt that has a maturity term longer than 18 months. The covenant does not apply to debt issuance for refinancing and interest expenses do not include short-term interest expenses. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. The Company was in compliance with the test at fiscal year end 2010.

Inter-company debt

- As of December 31, 2010, EGD owned $825 million of non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid by either cash or non-retractable preferred shares of the Company. DBRS treats this entire amount as debt and does not assign any equity treatment to the securities.

Bank Lines/Liquidity

Credit facilities					**As at Dec. 31, 2010**
	Amount	**Drawn**	**Commercial Paper**	**Available**	**Expiry date**
Committed lines of credit	700.0	0.0	350.0	350.0	Sep. 2011
Uncommitted lines of credit*	12.0	8.0	0.0	4.0	
Total	**712.0**	**8.0**	**350.0**	**354.0**	

* The uncommitted lines of credit are at St. Lawrence Gas.

(CAD millions)	Dec. 10	Sep. 10	Jun. 10	Mar. 10	Dec. 09
Short term debt usage	350	445	157	260	527

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capital expenditures. Working capital requirements are very seasonal and are also heavily influenced by the volatility of gas prices. These fluctuating capital requirements are mainly supported by the Company's commercial paper (CP) program.

- The Company has a $700 million CP program of which $350 million was available at the end of 2010. The CP program is fully backed by a $700 million 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate, given the current low gas price environment; nevertheless, the Company remains exposed to gas price volatility. A combination of cold weather and high gas prices could exhaust the Company's available liquidity, however, this is unlikely given the relatively current low gas price environment.

Regulation

Regulatory Overview
The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly rate adjustments. Therefore, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution
In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan to a maximum of an additional two years.

This IR methodology adjusts revenues every year, not rates, and relies on an annual process to forecast volume and customer additions. Unlike the Cost of Service methodology utilized in prior years, the concepts of rate base and return on rate base are not relevant for the purpose of setting rates. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The Company's 2010 ROE of 8.39% will remain unchanged throughout the IR period. The equity component also remains at 36%. The gas commodity and upstream transportation costs will continue to be passed on to customers.

The OEB recently reviewed the current methodology for adjusting cost of capital for regulated entities starting in the 2010 rate year. The decision maintains a formulaic approach to setting ROE levels; however, the existing formula will be reset to address the relatively low current ROE level, and refined to reduce sensitivity to changes in government bond yields. This new approach will provide an initial ROE of 9.75% (since revised to 9.58%) to be incorporated in 2010 Cost of Service applications. For EGD, the full benefit of the higher allowed ROE is expected to be captured on renewal of the IR in 2013. In January 2011, the Ontario Division Court heard EGD's appeal of the OEB's decision not to adjust the 8.39% ROE in its IR settlement to the revised 9.75% regulated ROE for the purposes of EGD's IR earnings sharing formula. The sharing formula allows earnings in excess of the annual adjusted ROE, plus 100 bps, to be shared 50/50 with ratepayers. The Division Court decision is pending.

The key terms of the OEB approved IR framework (effective January 2008) are summarized as follows:

- *Revenue Per Customer Cap* – The settlement allows for the annual reset of volumes, with revenues increasing proportionately with the growth in the number of customers. The revenue per customer cap will continue to minimize the Company's exposure to declining average use of natural gas while providing an incentive for the Company to continue growing its customer base.

- *Revenue Escalation Factor* – The revenue escalation factor is comprised of an inflation component and an adjustment for customer growth. In addition to the annual inflation adjustment, revenues will also grow by the annual increase in the number of customers. Based on an assumed inflation rate of 2%, the combined inflation and growth factors is forecast to result in an overall revenue escalation averaging approximately 3% per year through the term of the plan.

- *Earnings Sharing* – To align the interests of customers with the Company's shareholders, an earnings sharing mechanism forms part of the settlement. To the extent the actual utility return on equity represented by normalized earnings (i.e., excluding the effects of weather) exceeds the allowed utility return on equity (adjusted in accordance with provisions in the IR agreement), earnings will be shared with customers. The shareholders will retain the first 100 bps of ROE above the allowed ROE, while earnings represented by the ROE in excess of 100 bps above the allowed ROE will be shared equally with customers.

- *Adjustments* – There are several cost and deferral accounts that fall outside of the revenue escalation formula. The settlement provides for the recovery of capital invested in new power generation laterals, which is important given the significant capital requirements for such projects and their importance to Ontario's electricity needs. The Company is also allowed to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

- *Off Ramps* – An OEB review will be triggered if the Company's ROE varies more than 300 bps (either negatively or positively) relative to the allowed ROE. The review will determine the reasons for the variance in earnings and in such circumstances could result in adjustments to the settlement or a return to Cost of Service regulation. The review will not have an impact on earnings for prior years. The settlement does not preclude the Company from applying to the OEB for an increase in the embedded allowed ROE.

Gas Storage

EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB changed EGD's pricing policy in 2007.

Gas Distribution – New York

The Company owns St Lawrence Gas Company, which provides natural gas distribution services to 15,000 customers in New York State. The regulatory framework in New York is viewed as stable.

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

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Enbridge Gas Distribution Inc.

Balance Sheet
(CAD millions)

Assets	Dec. 31 2010	Dec. 31 2009	Dec. 31 2008	**Liabilities & Equity**	Dec. 31 2010	Dec. 31 2009	Dec. 31 2008
Cash + equivalents	-	-	100	S.t. & l.t.d. due 1yr.	500	677	1,026
Accounts receivable	802	769	980	A/P, accr'ds. & other	841	786	755
Gas in storage	400	396	656	**Current Liabilities**	1,341	1,463	1,781
Other current assets	-	33	23	Def'd. taxes + credits	1,229	1,157	14
Current Assets	1,202	1,197	1,759	Long-term debt	2,267	2,015	2,167
Net fixed assets	4,458	4,290	3,514	Loans from affiliate	375	375	375
Other assets	654	666	186	Perpetual pfds.	100	100	100
Investments in affiliate	825	825	825	Shareholders' equity	1,827	1,867	1,848
Total	7,139	6,978	6,285	**Total**	7,139	6,978	6,285

Ratio Analysis	Dec 31	Dec 31	Dec 31	Dec 31	Dec 31
Liquidity Ratios	2010	2009	2008	2007	2006
Current ratio	.90x	.82x	.99x	.98x	1.08x
Accumulated depreciation/gross fixed assets	25.5%	25.0%	36.0%	35.6%	34.7%
Cash flow/capital expenditures	1.33x	1.40x	1.19x	1.09x	0.72x
Cash flow-dividends/capital expenditures	0.76x	0.91x	0.81x	0.92x	0.27x
Cash flow/adjusted debt (1)	17.5%	19.3%	15.3%	14.5%	9.1%
Total debt/capital (incl intercompany loan)	54.6%	53.5%	57.9%	56.1%	59.8%
Total debt/capital (excl. intercompany loan)	59.2%	58.1%	62.3%	60.8%	64.7%
Deemed equity	36%	36%	36%	36%	35%
Dividend payout ratio	99.1%	76.6%	75.1%	36.9%	141.1%
Coverage Ratios					
EBITDA interest coverage (1)	3.86x	3.91x	3.63x	3.31x	2.83x
EBIT interest coverage (1)	2.43x	2.60x	2.46x	2.24x	1.80x
Fixed-charges coverage	2.39x	2.54x	2.38x	2.16x	1.74x
Debt/EBITDA	3.80x	3.54x	4.28x	4.09x	5.27x
Earnings Quality/Operating Efficiencies & Statistics					
Operating margin	35.9%	39.2%	40.3%	39.0%	33.4%
Net margin	19.2%	21.2%	19.7%	17.8%	13.7%
Return on common equity	11.5%	12.9%	12.0%	11.2%	7.9%
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.74%
Degree day deficiency - % normal	97.7%	107.2%	107.3%	101.2%	89.6%
Customer growth	2.0%	2.0%	2.0%	2.3%	3.7%

(1) Includes note receivable from parent company and investment in affiliate company.

Enbridge Gas Distribution Inc.

Report Date:
April 25, 2011

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2010	2009	2008	2007	2006
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Notes:
All figures are in Canadian dollars unless otherwise noted.

VT INCEPIT SIC PERMANET FIDELIS
Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2009-0084**

VOLUME: **Consultation Process on Cost of Capital Review Stakeholder Conference**

DATE: **September 21, 2009**

EB-2009-0048

THE ONTARIO ENERGY BOARD

IN THE MATTER OF a consultation by the Ontario Energy Board on the Cost of Capital for Electricity Distribution Companies

Conference held at 2300 Yonge Street, 25th Floor, Toronto, Ontario, on Monday, September 21, 2009, commencing at 9:30 a.m.

DAY 1

HOWARD WETSTON	Chair
PAMELA NOWINA	Vice-Chair
GORDON KAISER	Vice-Chair
KRISTI SEBALJ	Board Counsel
MARY ANNE ALDRED	
MARK GARNER	Board Staff
LISA BRICKENDEN	
ALEXANDRE RUEST	
KEITH RITCHIE	
KAREN TAYLOR	
MATTHEW AKMAN	Capital Markets Panel
STEPHEN DAFOE	
HAROLD HOLLOWAY	
ALEXANDRA ZVARICH	

…(previous transcription not included)

MR. GARNER: I think we can get copies of them up and around for everybody right away. We'll make sure we have that by the break. Thank you for raising that. Stephen.

PRESENTATION BY MR. DAFOE:

MR. DAFOE: Thank you. It’s Stephen Dafoe. I’m Director of Corporate Bond Research at Scotia Capital.

And I'll begin presentation just by describing the Canadian corporate bond market and my role as a corporate bond research analyst. First of all, debt financing makes up 60 percent of an electricity LDC's total capitalization, 64 percent for natural gas distributors. Now, public bond issues give the cheapest cost of debt financing, compared to other forms of financing such as commercial or corporate bank lending in the private placement market. This cheaper financing, though, is only available for those issuers large enough to issue a bond in the public market, and several but not all the Ontario LDCs have that kind of scale.

My role in the bond market is as a corporate bond research analyst. The work I publish and present is read by Canadian and international institutional investors and these are mainly professional pension, insurance, and mutual fund bond portfolio managers. The intention of my research is to offer facts, analyses of facts, and opinion on company and industry fundamentals and on bond market trends. Now, this aids professional bond investors in constructing efficient bond portfolios, getting fair returns for their beneficiaries and investors, and avoiding unnecessary risks. And very often this kind of research involves giving insight into credit ratings.

Bond investors use credit ratings in constructing portfolios in assessing the price of individual bond issues and trying to anticipate the risks of the bonds they're considering for investment.

The intention of the ratings is to help the bond investor assess future uncertainty that can affect bond values.

And very often, part of my job is assessing how the rating agencies are likely to react to emerging new developments. Essentially, I'm expected to anticipate what the rating agencies are likely to do next, either leaving ratings unchanged, moving them up, or moving them down.

Now, the bond market is often -- seems harder to understand even than the equity markets for a number of reasons. First of all, each bond issue issued by any company, and a single company can have many individual bond issues, each bond issue is unique. Even among bonds that have the same main features, rank the same and feature the same covenants, a different maturity date distinguishes each bond issue as a unique security. This is different than the stock market, where generally speaking each new issuance of a company's common equity is the same and the pool of common equity grows over time if the company is growing. This means the liquidity of a company stock also tends to improve over time -- of course that depends on market conditions -- but a bond issues liquidity depends mainly on the size of that individual issue, not on the size of the company. And liquidity is often a selling and pricing consideration of new issues, and generally speaking, bigger is most often better.

The Canadian corporate bond market is a private market, which means the bonds are not exchange-traded. So secondary market prices are available on a fee-for-service basis to market participants but generally speaking ,price discovery can sometimes be a challenge for individual bond issues, especially small ones that trade very infrequently.

Now, the relatively less frequent trading of individual bonds compared to common stock, and consequent lower liquidity in the bond market means successfully pricing and selling new issues can be challenging even for large issuers but especially for the small issuer. And again, even the larger Ontario LDCs often fall in the small and infrequent new issuer category.

This can and often does increase the challenges of successfully selling new issues of debt at a cost of borrowing favourable to the company.

Now, why does the bond market care about returns to equity investors? Well, quite simply, the regulatory allowed ROEs, together with deemed equity capitalization, dictates the utilities credit metrics. Ratios like interest coverage, FFO to debt, FFO interest coverage, FFO debt service requirements, free cash flow, all these and other credit ratios are affected by the ROE in capitalization. And they're examined by rating agencies and bond investors to gauge financial performance and make inferences about future financial risk.

These credit metrics affect the credit ratings, which of course influences the cost of new utility borrowing, the spreads on outstanding bonds, and the value of existing bond portfolios.

So these are ample reasons for the bond investor to be very concerned about allowed ROEs and deemed equity capitalization levels.

However, during an upswing in a utilities' capital spending cycle, the utility needs new equity to maintain that regulatory deemed capitalization ratio. And this is true whether the company's -- whether the stock of the utility is publicly traded and the company can raise new equity directly in the stock market, or if ownership is private, and, in that case, the company has to increase its retained earnings even if this means the owner is foregoing dividends.

Hence, during an upswing in the capital spending cycle, bondholders want a utility's equity investors to be satisfied enough with the company's financial prospects to put in new equity, as required, to maintain the debt-to-capitalization exactly or very close to the deemed regulatory capitalization.

Now, I'd like to take a look back a little bit at the evolution of my views on ROE in the utility sector, and

I'll illustrate this with the cost of debt financing of a sample high investment grade regulated utility from the date of a 30-year bond issue in June 2000.

The spread in percent, which the bond market -- which is the bond market's shorthand of how much higher the yield is compared to its Government of Canada benchmark is shown on the right-hand side of this chart.

So the chart shows a 2030 maturity bond. It's important to note that what's shown is not a constant term to maturity of any given issuer's debt. This is a single bond issued in 2000, and its maturity is declining over time. So all things being equal, its spread should have declined materially over the nearly ten years that it's been outstanding.

Of course, nothing has been equal over the past year, and the most obvious feature of this spread chart is the staggering jump in the yield in late 2000 and into early 2009. Rising spreads imply falling secondary market values of corporate bonds.

Now, the spike in spreads in late 2008, early 2009, was without precedent for many or most current bond investors and coincided with the global repricing of risk. The rise in spreads has greatly improved since the worst, but will have lingering effects for a long time. But the general contour of the bond spread of this typical Ontario regulated utility helps to illustrate the evolution of my views as a bond analyst on the Canadian and Ontario utility sectors.

Early in the decade, my written research and presentations to investors, I was generally bullish on utility bond values. I thought utilities, including the Ontario LDCs, offered attractive risk rewards for bond investors.

Now, there was some disruption of volatility in bond spreads in the early part of the decade, but, by and large, Canadian utility bond spreads tended to perform quite well over most of the decade. So apart from some uncomfortable periods, my benign view was borne out and bond spreads tended to tighten through the early and middle period of the decade.

By mid decade, many Canadian utility owners felt ROEs and equity capitalization levels were too low. Rate applications during this time tended to ask for higher capitalization and higher ROEs. However, in my written research during this period, I still expressed the view that provided the regulatory regimes remained stable and the risk of utilities of under-earning the allowed ROE was very, very low, financial performance was sufficient for the bond investor.

Now, for what I think was a variety of reasons - things like evolving and improving industry best practices, technological changes that brought productivity gains and overall good management and other things - during this period the sector was able to consistently meet, and sometimes better, the allowed ROE targets. And this seemed to bear out the thesis that the risks in the sector were low enough to rationalize, if not entirely justify, the prevailing low ROEs at least from the perspective of the bond investor.

And during this time, in my written work and presentations, I critiqued the rating agencies often for being overly cautious about financial ratios given industry's track record of stability.

But I have to add, in the middle part of the decade, along with other market participants, I recognized that utility bonds were not always an especially good value. However, alternatives in most other sectors in the Canadian bond market were also priced to perfection, so to speak. All spreads were low in the middle of the decade.

In hindsight, of course, it seems pretty clear today that the tight corporate bond spread prevailing in the 2004-2007 period are now viewed by many as too low and not likely to recur in the near to medium term.

In the past two years, both changing fundamentals in the industry, but, more important, changing bond and equity market conditions, well, they've changed quite dramatically. And so in my written research and presentations to investors, my opinion has evolved as well. In the past two years, I've become quite concerned about the effect lower ROEs is having on credit quality.

So what has changed since then? First and foremost, for a number of reasons, some of which I discussed in my written submission to the OEB in April, ROEs continue to fall with long Canada bond yields. At the same time, especially in the last two years, the real-world cost of capital was rising.

The effect has been to squeeze the credit ratios that are followed by bond investors and the rating agencies.

As well, the utility industry is becoming more complex. Things like consumer consciousness, demanding energy conservation, rising requirements to connect green generation, the rising cost of electricity that's far from over, volatile natural gas costs, technology changes, such as the introduction of smart meters, the current severe demand recession that's going to reduce consumption in revenue but won't obviate the capital spending requirements to connect new loads. The list goes on and on.

For the bond investor, all this means increased complexity, which means increased uncertainty over what the future might bring, which equals increased risk.

The lower ROEs and higher complexity is coming at a time when many and probably all utilities are entering a generational cycle of capital spending on top of demand growth and technical change. And all this brings pressure on both business risks and utility credit ratios, particularly interest coverage and free cash flow.

So we all know that ratings can influence the new issue spread and the secondary market of existing bond portfolios. So the next relevant question then becomes: What might the rating agencies do about all this?

First, I'd like to recall the March 6, 2003 Credit Watch experience. A major credit rating agency placed the whole Canadian utility sector on heightened risk of ratings downgrades. I'm pretty sure a few people in the room here remember that event quite well.

My recollection is that the explanations given for the rating actions were not well understood by the financial markets. In fact, I think some questioners on the conference call were politely skeptical of the reasoning offered. Others were more openly incredulous. And having had many conferences with fixed income investors about this at the time, I can say that the experience was viewed by many, and probably most, investors as a false alarm. And yet it still affected utility spreads for yearly a year, even though investors mostly disagreed.

This underlines the effect that ratings can and do have on corporate bond borrowers' cost of debt financing.

Now, getting back to the present day, the rating agencies have to date been nearly silent on the subject of declining ROEs. In my view, this is quite possibly due to a reluctance on their part to interject themselves into the regulatory process. This is quite appropriate, and certainly quite understandable following the experience of 2003.

However, no one should assume that the rating agencies are indifferent to pressure on utility credit ratios. Time and again, in rating agencies' published reports on utilities, we see the phrase "credit metrics are weak for the ratings". To me, this is a caution to the reader that fair warning has been given. "Credit metrics are weak for the rating" means that the agencies can only have so much tolerance for the degree credit ratios weakening, or the duration of the time period where weak credit ratios are expected to continue.

Even if the agencies refuse to interject themselves in the regulatory process by refraining from directly commenting on ROEs, I would not infer that they are indifferent to how the sector deals with the cost of capital issue.

In this context, I have a further concern about how the rating agencies might react to persistent low ROEs and what might happen if they eventually downgrade. If ratings downgrades were made and investors actually agreed with the rating agencies' reasoning that credit risk in the sector was rising, in that case the spread valuation impact would, in my view, be likely more substantial and material and long lasting than was the case in Credit Watch of 2003.

Now, let me illustrate how various events can influence bond spreads, going back to March 2002 on this same utility bond. Fallout from utility defaults in the United States, distress in the US cable sector stemming from a high profile bankruptcy, distress in the banking sector from banks' exposure to US utility and cable sectors, all caused Canadian corporate bond spreads, even the spreads of Canadian regulated utilities, to rise.

In March 2003, you can see a spike in the spread caused from a rating action by that major rating agency, even though most investors thought it was a false alarm.

This materially widened spreads for the better part of a year, even as the overall corporate bond market was in a recovery phase from the events of 2002.

Then of course in the right-hand side we see the obvious spike in spreads from the fall 2008 financial crisis.

The next arrow, in March 17th, 2009, this is the day the NEB released its TQM decision. Many utility analysts and investors view this as a favourable precedent, likely to be followed by cost of capital reviews by other Canadian regulators. Now, it's hard to discern what effect this event had on the Canadian bond market because it happened at the same time as the beginnings of a dramatic improvement in overall financial conditions globally.

However, I think that the TQM decision did help utility bonds to be the first sector in the Canadian corporate bond market to improve in a big way.

On June 18, 09, this coincided with the OEB announcing that there was not yet sufficient basis to immediately increase allowed ROEs. I think this disappointed the bond market to some degree though at the same time, of course, this consultative process was initiated.

These have all been material events for utility bond spreads, and I think this illustrates why I'm concerned that this cost of capital discussion is quite material to the bond market.

So, to conclude, and sum up my presentation here, while rating agencies have made few explicit references to falling ROEs, their caution: Credit ratios are weak for the ratings, has been abundant and frequent. As a corporate bond analyst, I truly think that in the absence of some relief on the cost of capital, pressure on credit ratios coming at the same time as rising CAPEX requirements, and along with other complexities being introduced in the sector brings the risk of downgrades in the sector that is real.

Additionally, if downgrades do occur and if the rating agencies agree the sector is riskier, the cost of new debt financing could be materially higher than it's been for most of the past decade.

And this is all the more relevant to the Ontario sector given status of even the larger LDCs as relatively small issuers in the Canadian bond market. For small issuers, successfully placing new bond issues can at times be tricky.

And according to accepted regulatory principles, higher cost of new financing for the utilities is borne by ratepayers. So I think that the corollary effects of allowed ROEs and deemed equity capitalization levels on the utilities’ cost of debt are material to the companies and ratepayers and should be considered by the regulator and other stakeholders.

I understand that the OEB's focus in the consultation on the cost of capital is the application of the fair return standard as it applies to a utility’s equity investors. That is as it should be. The core of the investigation should be an evidence-based assessment of what level of ROE, along with deemed capitalization, allows the utility's owner to achieve a return commensurate with investments of similar risk in today's capital markets. But the fair return standard also references the utility’s ability to maintain its financial integrity and enables the utility to attract capital at a reasonable cost on reasonable terms and conditions. I view these aspects of the fair return standard as directly applicable to the utility's ongoing ability to raise funding in the bond market or other debt markets at optimal rates.

In hindsight, I think it's fair to say that in the middle part of this decade, utilities were able to take the Canadian public bond market for granted. It certainly offered abundant, long-term financing at a favourable cost of borrowing. However, Canadian corporate bond market conditions have changed. Along with all investment markets globally, risk is being repriced at higher levels.

To sum up, I think these corollary debt financing factors, while not central to answering the fair return on equity question, should be borne in mind by all participants in the broad cost of capital discussion.

And before I pass on the microphone, I'd ask all participants to note this standard investment research disclaimer on my last slide. And to the extent I can clarify my remarks and opinions, I'm happy to participate in the Q&A session following the last speaker.

MR. GARNER: Thank you, Stephen. Harold.

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

E - Operating Revenue
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Ref: Exhibit E2, Tab 1, Schedule 1

a) Has EGD reflected the ROE of 9.03% shown in Exhibit E2, Tab 1, Schedule 1, Updated in the calculation of the gross revenue deficiency of $91.3 million shown in Exhibit F3, Tab 1, Schedule 1?

b) If the response to part (a) is no, please indicate the impact on the gross revenue deficiency of moving from 9.42% to 9.03% ROE.

RESPONSE

a) The Company has filed Impact Statement Number 1 found at Exhibit M1, Tab 1, Schedule 1, on June 1, 2012 which included an update to ROE of 9.03%.

b) See part a).

Witnesses: K. Culbert
R. Fischer
M. Lister
D. Yaworsky

CME, CCC, SEC, VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

Appendix A discusses ROE analysis: DCF Model

a) Please explain why Concentric does not use a two stage growth model.

b) Please provide Concentric's estimate of the long run nominal GDP growth rate in the US.

c) Please indicate how differences in analyst earnings growth rates which differ dramatically across different service providers can be reconciled. For example, for Southwest Gas the forecast growth rate varies from 9.0% for Value Line to 2.2% for Thomson First Call.

d) Are growth rates subject to an "optimism bias". If so, how has Concentric adjusted for this?

e) Please indicate how many analysts are involved in the forecasts in Exhibit 05, pages 1 and 2.

f) Please indicate whether Concentric has used a "quarterly compounding" growth rate estimate for the forecast dividend yield and whether dividends are actually increased on a quarterly basis.

g) Please provide the quarterly dividend per share history for each US and Canadian firm in Concentric's analysis since 1990 to verify whether the dividends are increased annually or quarterly.

Witnesses: J. Coyne
J. Lieberman
Concentric

RESPONSE

a) Concentric generally does not employ a two-stage growth model for its DCF analysis. A distinct advantage of the DCF approach is its reliance on market based data and the inputs of equity analysts for growth rates. Inclusion of a second stage involves the introduction of an inherently more subjective estimate of the second stage growth rate. A single stage DCF model is reliant on equity analyst estimates of growth which are developed independently of the regulatory process. Selection of staged growth rates invariably creates controversy, as with the CAPM, due to a range of opinions on the reasonableness of inputs.

b) Concentric does not independently forecast GDP growth. According to the most recent long-term Blue Chip Forecast, U.S. nominal GDP is forecast to be 4.9%, the average of the two long-term 5-year average GDP forecasts.[1]

c) Analyst growth rates may vary widely among analysts, depending on their view of the economy, growth in the utility's service area, competing energy sources, and how the company will be able to capitalize on future growth opportunities. It would be impossible to reconcile these differences without discussing each assumption made with the equity analyst providing the estimate. However, it is possible to find a measure of central tendency among these analysts' estimates, i.e. the mean or median, which should serve as the best approximation of future growth for a given company. The more analyst estimates factored into the analysis, the less likely that one analyst could significantly impact the resulting growth rate. For this reason, Concentric has included multiple consensus estimates (which in themselves represent the central tendency of analyst estimates as a "consensus" estimate) of long-term growth in addition to the Value Line Survey estimate.

d) Concentric does not believe that analysts are biased. Regulators have separated the stock underwriting business from the research function in an effort to assure the independence and quality of analysts' buy and sell recommendations, as well as the objectivity of their estimates. Equity analysts do not have an incentive to provide overly optimistic research reports because much of this reporting is utilized by institutional clients such as pension funds or mutual funds, and credibility is very important in maintaining that business relationship. These clients expect forecasting accuracy in the reports of equity analysts. The Wall Street Journal publishes an annual ranking of the best equity analysts in each industry. The

[1] Blue Chip Economic Indicators, Top Analyst's Forecasts of the U.S. Economic Outlook for the Year Ahead Vol. 37, No. 3, Long-Range Consensus U.S. Economic Projections, March 10, 2012, at 15.

Witnesses: J. Coyne
J. Lieberman
Concentric

rankings are based to a large extent on the accuracy of the analysts' earnings forecasts and their buy and sell recommendations. Inclusion on this prestigious list is very important for both the analyst and the firm for which he or she works. There is ample evidence to support the conclusion that earnings estimates are reasonably accurate, and accordingly are relied upon by utility investors.

e)

		Number of Estimates		
Company	Ticker	Bloomberg	Yahoo! / Thomson First Call	Zacks
National Fuel Gas Company	NFG	-	9	6
Northwest Natural Gas Company	NWN	10	8	8
Piedmont Natural Gas Co.	PNY	9	6	7
Questar Corporation	STR	-	8	5
Sempra Energy	SRE	14	12	9
Southwest Gas Corporation	SWX	9	9	7
Vectren Corporation	VVC	10	7	7
Canadian Utilities Ltd.	CU	-	5	-
Emera Inc.	EMA	-	7	-
Enbridge Inc.	ENB	16	8	-
Fortis Inc.	FTS	-	6	-
TransCanada Corp.	TRP	-	14	-

f) Concentric does not use quarterly-compounding of dividend yield growth in its Constant Growth DCF model. Dividends are not increased on a quarterly basis.

g) The quarterly dividend per share history for each US and Canadian firm in Concentric's analysis since 1990, or as available, has been attached.

Witnesses: J. Coyne
J. Lieberman
Concentric

Source: Bloomberg

NFG US Equity		NWN US Equity		PNY US Equity	
Date	EQY_DPS	Date	EQY_DPS	Date	EQY_DPS
3/30/1990	0.1675	3/30/1990	0.2733	3/30/1990	0.105
6/29/1990	0.1775	6/29/1990	0.2733	6/29/1990	0.105
9/28/1990	0.1775	9/28/1990	0.2733	9/28/1990	0.105
12/31/1990	0.1775	12/31/1990	0.28	12/31/1990	0.105
3/29/1991	0.1775	3/29/1991	0.28	3/29/1991	0.11
6/28/1991	0.1825	6/28/1991	0.28	6/28/1991	0.11
9/30/1991	0.1825	9/30/1991	0.28	9/30/1991	0.11
12/31/1991	0.1825	12/31/1991	0.2867	12/31/1991	0.11
3/31/1992	0.1825	3/31/1992	0.2867	3/31/1992	0.115
6/30/1992	0.1875	6/30/1992	0.2867	6/30/1992	0.115
9/30/1992	0.1875	9/30/1992	0.2867	9/30/1992	0.115
12/31/1992	0.1875	12/31/1992	0.2867	12/31/1992	0.115
3/31/1993	0.1875	3/31/1993	0.2867	3/31/1993	0.1225
6/30/1993	0.1925	6/30/1993	0.2933	6/30/1993	0.1225
9/30/1993	0.1925	9/30/1993	0.2933	9/30/1993	0.1225
12/31/1993	0.1925	12/31/1993	0.2933	12/31/1993	0.1225
3/31/1994	0.1925	3/31/1994	0.2933	3/31/1994	0.13
6/30/1994	0.1975	6/30/1994	0.2933	6/30/1994	0.13
9/30/1994	0.1975	9/30/1994	0.2933	9/30/1994	0.13
12/30/1994	0.1975	12/30/1994	0.2933	12/30/1994	0.13
3/31/1995	0.1975	3/31/1995	0.2933	3/31/1995	0.1375
6/30/1995	0.2025	6/30/1995	0.2933	6/30/1995	0.1375
9/29/1995	0.2025	9/29/1995	0.2933	9/29/1995	0.1375
12/29/1995	0.2025	12/29/1995	0.3	12/29/1995	0.1375
3/29/1996	0.2025	3/29/1996	0.3	3/29/1996	0.145
6/28/1996	0.21	6/28/1996	0.3	6/28/1996	0.145
9/30/1996	0.21	9/30/1996	0.3	9/30/1996	0.145
12/31/1996	0.21	12/31/1996	0.3	12/31/1996	0.145
3/31/1997	0.21	3/31/1997	0.3	3/31/1997	0.1525
6/30/1997	0.2175	6/30/1997	0.3	6/30/1997	0.1525
9/30/1997	0.2175	9/30/1997	0.3	9/30/1997	0.1525
12/31/1997	0.2175	12/31/1997	0.305	12/31/1997	0.1525
3/31/1998	0.2175	3/31/1998	0.305	3/31/1998	0.1625
6/30/1998	0.225	6/30/1998	0.305	6/30/1998	0.1625
9/30/1998	0.225	9/30/1998	0.305	9/30/1998	0.1625
12/31/1998	0.225	12/31/1998	0.305	12/31/1998	0.1625
3/31/1999	0.225	3/31/1999	0.305	3/31/1999	0.1725
6/30/1999	0.2325	6/30/1999	0.31	6/30/1999	0.1725
9/30/1999	0.2325	9/30/1999	0.305	9/30/1999	0.1725
12/31/1999	0.2325	12/31/1999	0.305	12/31/1999	0.1725
3/31/2000	0.2325	3/31/2000	0.31	3/31/2000	0.1825
6/30/2000	0.24	6/30/2000	0.31	6/30/2000	0.1825

9/29/2000	0.24	9/29/2000	0.31	9/29/2000	0.1825
12/29/2000	0.24	12/29/2000	0.31	12/29/2000	0.1825
3/30/2001	0.12	3/30/2001	0.31	3/30/2001	0.1925
6/29/2001	0.2525	6/29/2001	0.31	6/29/2001	0.1925
9/28/2001	0.252	9/28/2001	0.31	9/28/2001	0.1925
3/29/2002	0.252	12/31/2001	0.315	12/31/2001	0.1925
6/28/2002	0.26	3/29/2002	0.315	3/29/2002	0.2
9/30/2002	0.26	6/28/2002	0.315	6/28/2002	0.2
12/31/2002	0.26	9/30/2002	0.315	9/30/2002	0.2
3/31/2003	0.26	12/31/2002	0.315	12/31/2002	0.2075
6/30/2003	0.27	3/31/2003	0.315	3/31/2003	0.2075
9/30/2003	0.27	6/30/2003	0.315	6/30/2003	0.2075
12/31/2003	0.27	9/30/2003	0.315	9/30/2003	0.2
3/31/2004	0.27	12/31/2003	0.325	12/31/2003	0.2075
6/30/2004	0.28	3/31/2004	0.325	3/31/2004	0.215
9/30/2004	0.28	6/30/2004	0.325	6/30/2004	0.215
12/31/2004	0.28	9/30/2004	0.325	9/30/2004	0.215
3/31/2005	0.28	12/31/2004	0.325	12/31/2004	0.215
6/30/2005	0.29	3/31/2005	0.325	3/31/2005	0.23
9/30/2005	0.29	6/30/2005	0.325	6/30/2005	0.23
12/30/2005	0.29	9/30/2005	0.325	9/30/2005	0.23
3/31/2006	0.29	12/30/2005	0.345	12/30/2005	0.23
6/30/2006	0.3	3/31/2006	0.345	3/31/2006	0.24
9/29/2006	0.3	6/30/2006	0.345	6/30/2006	0.24
12/29/2006	0.3	9/29/2006	0.345	9/29/2006	0.24
3/30/2007	0.3	12/29/2006	0.355	12/29/2006	0.24
6/29/2007	0.31	3/30/2007	0.355	3/30/2007	0.25
9/28/2007	0.31	6/29/2007	0.355	6/29/2007	0.25
12/31/2007	0.31	9/28/2007	0.355	9/28/2007	0.25
3/31/2008	0.31	12/31/2007	0.375	12/31/2007	0.25
6/30/2008	0.325	3/31/2008	0.375	3/31/2008	0.26
9/30/2008	0.325	6/30/2008	0.375	6/30/2008	0.26
12/31/2008	0.325	9/30/2008	0.375	9/30/2008	0.26
3/31/2009	0.325	12/31/2008	0.395	12/31/2008	0.26
6/30/2009	0.335	3/31/2009	0.395	3/31/2009	0.27
9/30/2009	0.335	6/30/2009	0.395	6/30/2009	0.27
12/31/2009	0.335	9/30/2009	0.395	9/30/2009	0.27
3/31/2010	0.335	12/31/2009	0.415	12/31/2009	0.27
6/30/2010	0.345	3/31/2010	0.415	3/31/2010	0.28
9/30/2010	0.345	6/30/2010	0.415	6/30/2010	0.28
12/31/2010	0.345	9/30/2010	0.415	9/30/2010	0.28
3/31/2011	0.345	12/31/2010	0.435	12/31/2010	0.28
6/30/2011	0.355	3/31/2011	0.435	3/31/2011	0.29
9/30/2011	0.355	6/30/2011	0.435	6/30/2011	0.29
12/30/2011	0.355	9/30/2011	0.435	9/30/2011	0.29
3/30/2012	0.355	12/30/2011	0.445	12/30/2011	0.29
		3/30/2012	0.445	3/30/2012	0.3

STR US Equity		SRE US Equity		SWX US Equity
Date	EQY_DPS	Date	EQY_DPS	Date
3/30/1990	0.06	3/31/1997	0	3/31/1992
6/29/1990	0.06	6/30/1997	0	6/30/1992
9/28/1990	0.0613	9/30/1997	0	9/30/1992
12/31/1990	0.0613	12/31/1997	0	12/31/1992
3/29/1991	0.0613	6/30/1998	0.46	3/31/1993
6/28/1991	0.0637	9/30/1998	0.39	6/30/1993
9/30/1991	0.0637	12/31/1998	0.39	9/30/1993
12/31/1991	0.0637	3/31/1999	0.39	12/31/1993
3/31/1992	0.0637	6/30/1999	0.39	3/31/1994
6/30/1992	0.0637	9/30/1999	0.39	6/30/1994
9/30/1992	0.0662	12/31/1999	0.39	9/30/1994
12/31/1992	0.0662	3/31/2000	0.25	12/30/1994
3/31/1993	0.0662	6/30/2000	0.25	3/31/1995
6/30/1993	0.0687	9/29/2000	0.25	6/30/1995
9/30/1993	0.0687	12/29/2000	0.25	9/29/1995
12/31/1993	0.0687	3/30/2001	0.25	12/29/1995
3/31/1994	0.0687	6/29/2001	0.25	3/29/1996
6/30/1994	0.0713	9/28/2001	0.25	6/28/1996
9/30/1994	0.0713	12/31/2001	0.25	9/30/1996
12/30/1994	0.0712	3/29/2002	0.25	12/31/1996
3/31/1995	0.0712	6/28/2002	0.25	3/31/1997
6/30/1995	0.0712	9/30/2002	0.25	6/30/1997
9/29/1995	0.0737	12/31/2002	0.25	9/30/1997
12/29/1995	0.0737	3/31/2003	0.25	12/31/1997
3/29/1996	0.0737	6/30/2003	0.25	3/31/1998
6/28/1996	0.0737	9/30/2003	0.25	6/30/1998
9/30/1996	0.0737	12/31/2003	0.25	9/30/1998
12/31/1996	0.0763	3/31/2004	0.25	12/31/1998
3/31/1997	0.0763	6/30/2004	0.25	3/31/1999
6/30/1997	0.0763	9/30/2004	0.25	6/30/1999
9/30/1997	0.0787	12/31/2004	0.25	9/30/1999
12/31/1997	0.0787	3/31/2005	0.29	12/31/1999
3/31/1998	0.0787	6/30/2005	0.29	3/31/2000
6/30/1998	0.0825	9/30/2005	0.29	6/30/2000
9/30/1998	0.0825	12/30/2005	0.29	9/29/2000
12/31/1998	0.0825	3/31/2006	0.3	12/29/2000
3/31/1999	0.0825	6/30/2006	0.3	3/30/2001
6/30/1999	0.0825	9/29/2006	0.3	6/29/2001
9/30/1999	0.085	12/29/2006	0.3	9/28/2001
12/31/1999	0.085	3/30/2007	0.31	12/31/2001
3/31/2000	0.085	6/29/2007	0.31	3/29/2002
6/30/2000	0.085	9/28/2007	0.31	6/28/2002

9/29/2000	0.085	12/31/2007	0.31	9/30/2002
12/29/2000	0.0875	3/31/2008	0.32	12/31/2002
3/30/2001	0.0875	6/30/2008	0.35	3/31/2003
6/29/2001	0.0875	9/30/2008	0.35	6/30/2003
9/28/2001	0.0875	12/31/2008	0.35	9/30/2003
12/31/2001	0.09	3/31/2009	0.39	12/31/2003
3/29/2002	0.09	6/30/2009	0.39	3/31/2004
6/28/2002	0.09	9/30/2009	0.39	6/30/2004
9/30/2002	0.09	12/31/2009	0.39	9/30/2004
12/31/2002	0.0925	3/31/2010	0.39	12/31/2004
3/31/2003	0.0925	6/30/2010	0.39	3/31/2005
6/30/2003	0.0925	9/30/2010	0.39	6/30/2005
9/30/2003	0.1025	12/31/2010	0.39	9/30/2005
12/31/2003	0.1025	3/31/2011	0.48	12/30/2005
3/31/2004	0.1025	6/30/2011	0.48	3/31/2006
6/30/2004	0.1075	9/30/2011	0.48	6/30/2006
9/30/2004	0.1075	12/30/2011	0.48	9/29/2006
12/31/2004	0.1075	3/30/2012	0.6	12/29/2006
3/31/2005	0.1075			3/30/2007
6/30/2005	0.1125			6/29/2007
9/30/2005	0.1125			9/28/2007
12/30/2005	0.1125			12/31/2007
3/31/2006	0.1125			3/31/2008
6/30/2006	0.1175			6/30/2008
9/29/2006	0.1175			9/30/2008
12/29/2006	0.1175			12/31/2008
3/30/2007	0.1175			3/31/2009
6/29/2007	0.1225			6/30/2009
9/28/2007	0.1225			9/30/2009
12/31/2007	0.1225			12/31/2009
3/31/2008	0.1225			3/31/2010
6/30/2008	0.1225			6/30/2010
9/30/2008	0.1225			9/30/2010
12/31/2008	0.125			12/31/2010
3/31/2009	0.125			3/31/2011
6/30/2009	0.125			6/30/2011
9/30/2009	0.125			9/30/2011
12/31/2009	0.13			12/30/2011
3/31/2010	0.13			3/30/2012
6/30/2010	0.13			
9/30/2010	0.14			
12/31/2010	0.14			
3/31/2011	0.1525			
6/30/2011	0.1525			
9/30/2011	0.1525			
12/30/2011	0.1625			
3/30/2012	0.1625			

	VVC US Equity		CU CN Equity	
EQY_DPS	Date	EQY_DPS	Date	EQY_DPS
0.175	3/31/2000	0	3/31/1993	0.1775
0.175	6/30/2000	0.243	6/30/1993	0.1775
0.175	9/29/2000	0.243	9/30/1993	0.1775
0.175	12/29/2000	0.255	12/31/1993	0.1775
0.175	3/30/2001	0.255	3/31/1994	0.18
0.175	6/29/2001	0.255	6/30/1994	0.18
0.195	9/28/2001	0.255	9/30/1994	0.18
0.195	12/31/2001	0.265	12/30/1994	0.18
0.195	3/29/2002	0.265	3/31/1995	0.1825
0.195	6/28/2002	0.265	6/30/1995	0.1825
0.205	9/30/2002	0.265	9/29/1995	0.1825
0.205	12/31/2002	0.275	12/29/1995	0.1825
0.205	3/31/2003	0.275	3/29/1996	0.185
0.205	6/30/2003	0.275	6/28/1996	0.185
0.205	9/30/2003	0.275	9/30/1996	0.185
0.205	12/31/2003	0.285	12/31/1996	0.185
0.205	3/31/2004	0.285	3/31/1997	0.195
0.205	6/30/2004	0.285	6/30/1997	0.195
0.205	9/30/2004	0.285	9/30/1997	0.195
0.205	12/31/2004	0.295	12/31/1997	0.195
0.205	3/31/2005	0.3	3/31/1998	0.205
0.205	6/30/2005	0.295	6/30/1998	0.205
0.205	9/30/2005	0.3	9/30/1998	0.205
0.205	12/30/2005	0.295	12/31/1998	0.205
0.205	3/31/2006	0.31	3/31/1999	0.215
0.205	6/30/2006	0.305	6/30/1999	0.215
0.205	9/29/2006	0.31	9/30/1999	0.215
0.205	12/29/2006	0.315	12/31/1999	0.215
0.205	3/30/2007	0.32	3/31/2000	0.225
0.205	6/29/2007	0.32	6/30/2000	0.225
0.205	9/28/2007	0.32	9/29/2000	0.225
0.205	12/31/2007	0.33	12/29/2000	0.225
0.205	3/31/2008	0.33	3/30/2001	0.235
0.205	6/30/2008	0.33	6/29/2001	0.235
0.205	9/30/2008	0.33	9/28/2001	0.235
0.205	12/31/2008	0.33	12/31/2001	0.235
0.205	3/31/2009	0.34	3/29/2002	0.245
0.205	6/30/2009	0.34	6/28/2002	0.245
0.205	9/30/2009	0.34	9/30/2002	0.245
0.205	12/31/2009	0.34	12/31/2002	0.245
0.205	3/31/2010	0.34	3/31/2003	0.255
0.205	6/30/2010	0.34	6/30/2003	0.255

0.205	9/30/2010	0.34	9/30/2003	0.255
0.205	12/31/2010	0.345	12/31/2003	0.255
0.205	3/31/2011	0.345	3/31/2004	0.265
0.205	6/30/2011	0.345	6/30/2004	0.265
0.205	9/30/2011	0.345	9/30/2004	0.265
0.205	12/30/2011	0.35	12/31/2004	0.265
0.205	3/30/2012	0.35	3/31/2005	0.275
0.205			6/30/2005	0.275
0.205			9/30/2005	0.275
0.205			12/30/2005	0.275
0.205			3/31/2006	0.285
0.205			6/30/2006	0.285
0.205			9/29/2006	0.54
0.205			12/29/2006	0.29
0.205			3/30/2007	0.305
0.205			6/29/2007	0.315
0.205			9/28/2007	0.315
0.205			12/31/2007	0.315
0.215			3/31/2008	0.3325
0.215			6/30/2008	0.3325
0.215			9/30/2008	0.3325
0.215			12/31/2008	0.3325
0.225			3/31/2009	0.3525
0.225			6/30/2009	0.3525
0.225			9/30/2009	0.3525
0.225			12/31/2009	0.3525
0.2375			3/31/2010	0.3775
0.2375			6/30/2010	0.3775
0.2375			9/30/2010	0.3775
0.2375			12/31/2010	0.3775
0.25			3/31/2011	0.4025
0.25			6/30/2011	0.4025
0.25			9/30/2011	0.4025
0.25			12/30/2011	0.4025
0.265			3/30/2012	0.4425
0.265				
0.265				
0.265				
0.295				

EMA CN Equity		ENB CN Equity		FTS CN Equity	
Date	EQY_DPS	Date	EQY_DPS	Date	EQY_DPS
3/31/1993	0.1875	3/31/1994	0.0625	3/31/1997	0.11
6/30/1993	0.1875	6/30/1994	0.0625	6/30/1997	0.11
9/30/1993	0.1875	9/30/1994	0.0625	9/30/1997	0.11
12/31/1993	0.1875	3/31/1995	0.0625	12/31/1997	0.11
3/31/1994	0.19	6/30/1995	0.0625	3/31/1998	0.1125
6/30/1994	0.19	9/29/1995	0.0625	6/30/1998	0.1125
9/30/1994	0.19	12/29/1995	0.0625	9/30/1998	0.1125
12/30/1994	0.19	3/29/1996	0.0625	12/31/1998	0.1125
3/31/1995	0.195	6/28/1996	0.0625	3/31/1999	0.1125
6/30/1995	0.195	9/30/1996	0.0644	6/30/1999	0.1125
9/29/1995	0.195	12/31/1996	0.0644	9/30/1999	0.1125
12/29/1995	0.195	3/31/1997	0.0644	12/31/1999	0.1125
3/29/1996	0.2	6/30/1997	0.0644	3/31/2000	0.115
6/28/1996	0.2	9/30/1997	0.0681	6/30/2000	0.115
9/30/1996	0.2	12/31/1997	0.0681	9/29/2000	0.115
12/31/1996	0.2	3/31/1998	0.0681	12/29/2000	0.115
3/31/1997	0.2025	6/30/1998	0.0681	3/30/2001	0.115
6/30/1997	0.2025	9/30/1998	0.0719	6/29/2001	0.1175
9/30/1997	0.2025	12/31/1998	0.0719	9/28/2001	0.1175
12/31/1997	0.2025	3/31/1999	0.0719	12/31/2001	0.1175
3/31/1998	0.205	6/30/1999	0.0758	3/29/2002	0.1175
6/30/1998	0.205	9/30/1999	0.0758	6/28/2002	0.1225
9/30/1998	0.205	12/31/1999	0.0072	9/30/2002	0.1225
3/31/1999	0.207	3/31/2000	0.0758	12/31/2002	0.13
6/30/1999	0.207	6/30/2000	0.0805	3/31/2003	0.13
9/30/1999	0.207	9/29/2000	0.0805	6/30/2003	0.13
12/31/1999	0.207	12/29/2000	0.0808	9/30/2003	0.13
3/31/2000	0.21	3/30/2001	0.0875	12/31/2003	0.135
6/30/2000	0.21	6/29/2001	0.0875	3/31/2004	0.135
9/29/2000	0.21	9/28/2001	0.0875	6/30/2004	0.135
12/29/2000	0.21	12/31/2001	0.0875	9/30/2004	0.135
3/30/2001	0.213	3/29/2002	0.095	12/31/2004	0.1425
6/29/2001	0.213	6/28/2002	0.095	3/31/2005	0.1425
9/28/2001	0.213	9/30/2002	0.095	6/30/2005	0.1425
12/31/2001	0.212	12/31/2002	0.095	9/30/2005	0.04
3/29/2002	0.215	3/31/2003	0.1037	12/30/2005	0.16
6/28/2002	0.215	6/30/2003	0.1037	3/31/2006	0.16
9/30/2002	0.215	9/30/2003	0.1037	6/30/2006	0.16
12/31/2002	0.215	12/31/2003	0.1037	9/29/2006	0.19
3/31/2003	0.215	3/31/2004	0.1145	12/29/2006	0.19
6/30/2003	0.215	6/30/2004	0.1145	3/30/2007	0.21
9/30/2003	0.215	9/30/2004	0.1145	6/29/2007	0.21

12/31/2003	0.215	12/31/2004	0.1145	9/28/2007	0.21
3/31/2004	0.22	3/31/2005	0.125	12/31/2007	0.25
6/30/2004	0.22	6/30/2005	0.125	3/31/2008	0.25
9/30/2004	0.22	9/30/2005	0.125	6/30/2008	0.25
12/31/2004	0.22	12/30/2005	0.1685	9/30/2008	0.25
3/31/2005	0.2225	3/31/2006	0.1437	12/31/2008	0.27
6/30/2005	0.2225	6/30/2006	0.1437	3/31/2009	0.26
9/30/2005	0.2225	9/29/2006	0.1437	6/30/2009	0.26
12/30/2005	0.2225	12/29/2006	0.145	9/30/2009	0.26
3/31/2006	0.2225	3/30/2007	0.1538	12/31/2009	0.26
6/30/2006	0.2225	6/29/2007	0.1538	3/31/2010	0.56
9/29/2006	0.2225	9/28/2007	0.1538	6/30/2010	0.28
12/29/2006	0.2225	12/31/2007	0.1538	9/30/2010	0.28
3/30/2007	0.2225	3/31/2008	0.165	12/31/2010	0.28
6/29/2007	0.2225	6/30/2008	0.165	3/31/2011	0.29
9/28/2007	0.2275	9/30/2008	0.165	6/30/2011	0.29
12/31/2007	0.2275	12/31/2008	0.165	9/30/2011	0.29
3/31/2008	0.2375	3/31/2009	0.185	12/30/2011	0.29
6/30/2008	0.2375	6/30/2009	0.185	3/30/2012	0.3
9/30/2008	0.2375	9/30/2009	0.185		
12/31/2008	0.2525	12/31/2009	0.185		
3/31/2009	0.2525	3/31/2010	0.2125		
6/30/2009	0.2525	6/30/2010	0.2125		
9/30/2009	0.525	9/30/2010	0.2125		
12/31/2009	0.2725	12/31/2010	0.2125		
3/31/2010	0.2725	3/31/2011	0.245		
6/30/2010	0.2825	6/30/2011	0.245		
9/30/2010	0.6075	9/30/2011	0.245		
12/31/2010	0	12/30/2011	0.245		
3/31/2011	0.325	3/30/2012	0.2825		
6/30/2011	0.325				
9/30/2011	0.6625				
12/30/2011	0				
3/30/2012	0.3375				

TRP CN Equity

Date	EQY_DPS
3/31/1993	0.21
6/30/1993	0.21
9/30/1993	0.21
12/31/1993	0.23
3/31/1994	0.23
6/30/1994	0.23
9/30/1994	0.23
12/30/1994	0.25
3/31/1995	0.25
6/30/1995	0.25
12/29/1995	0.77
3/29/1996	0.27
6/28/1996	0.27
9/30/1996	0.27
12/31/1996	0.29
3/31/1997	0.29
6/30/1997	0.29
9/30/1997	0.29
12/31/1997	0.31
3/31/1998	0.31
6/30/1998	0.31
9/30/1998	0.28
12/31/1998	0.28
3/31/1999	0.28
6/30/1999	0.28
9/30/1999	0.28
12/31/1999	0.28
3/31/2000	0.2
6/30/2000	0.2
9/29/2000	0.2
12/29/2000	0.2
3/30/2001	0.225
6/29/2001	0.225
9/28/2001	0.225
12/31/2001	0.225
3/29/2002	0.25
6/28/2002	0.25
9/30/2002	0.25
12/31/2002	0.25
3/31/2003	0.27
6/30/2003	0.27
9/30/2003	0.27

12/31/2003	0.27
3/31/2004	0.29
6/30/2004	0.29
9/30/2004	0.29
12/31/2004	0.29
3/31/2005	0.305
6/30/2005	0.305
9/30/2005	0.305
12/30/2005	0.305
3/31/2006	0.32
6/30/2006	0.32
9/29/2006	0.32
12/29/2006	0.32
3/30/2007	0.34
6/29/2007	0.34
9/28/2007	0.34
12/31/2007	0.34
3/31/2008	0.36
6/30/2008	0.36
9/30/2008	0.36
12/31/2008	0.36
3/31/2009	0.38
6/30/2009	0.38
9/30/2009	0.38
12/31/2009	0.38
3/31/2010	0.4
6/30/2010	0.4
9/30/2010	0.4
12/31/2010	0.4
3/31/2011	0.42
6/30/2011	0.42
9/30/2011	0.42
12/30/2011	0.42
3/30/2012	0.44

CME, CCC, SEC, VECC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

Appendix A discusses ROE analysis: CAPM Model.

a) Please explain why Concentric uses a “long term forecast of the 10 year government bond yield” rather than the appropriate rate for the test year.

b) Please confirm that both Bloomberg and Value line routinely adjust actual betas by the Blume methodology that assumes that actual beta estimates have measurement error and thus average them with 1.0 the mean beta for the market as a whole.

c) Please indicate any Canadian regulator that has explicitly accepted the Blume beta adjustment methodology.

d) Please provide any research on the correct adjustment procedures for utility betas.

e) Please provide a copy of the reports referenced in footnote 43 (mainly the data tables) to replicate the claimed market risk premiums cited on page A-4.

f) Please confirm that the cited market risk premiums are for the relevant equity return over the return on long government bonds.

g) In terms of the “corroborating” evidence in Concentric 09 please conform that Concentric assumes that these growth rates (up to 667%) are valid inputs into the DCF model and fairly estimate the investor’s fair rate of return.

Witnesses: J. Coyne
J. Lieberman
Concentric

RESPONSE

a) Please refer to footnote 42, on page A-3 of Concentric's Report. Concentric has used the long- term forecast risk free rate as it best aligns with the period that rates will be in effect, i.e. 2013 – 2018.

b) Both Value Line and Bloomberg betas are adjusted to compensate for the tendency of beta to revert towards the market over time. Adjusting beta towards the market mean of 1.0 is based on a series of studies conducted by Marshall E. Blume, which found that there is a substantial tendency for the underlying values of beta to regress towards the market mean over time.[1]

c) Concentric is not aware of any Canadian regulator that has specifically mentioned the use of the Blume beta adjustment methodology. However, the 2009 BCUC decision found that beta **should be adjusted in a manner consistent with the practice generally followed by analysts**:

> The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.
>
> The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.[2]

Concentric interprets the Commission's statement to indicate that since Value Line and Bloomberg are the most widely-used sources for beta and equity market data, and their adjusted betas are those most commonly used in practice, it follows that the methodology those services employ to adjust beta would be acceptable to the BCUC Commission. This is confirmed by the Commission's conclusion on beta:

[1] Marshall E. Blume, The Journal of Finance, Vol. 30, No. 3. (Jun., 1975), p. 794.
[2] BCUC Commission Order 158-09 (December 16, 2009) at 45.

Witnesses: J. Coyne
J. Lieberman
Concentric

> Ms. McShane states that the "raw" calculated betas for the five-year period ending March 2009 of her sample of fifteen US utilities averaged 0.41, while the average reported Value Line beta for the sample (and the beta more likely to be relied upon by analysts and investors) was 0.66. (Exhibit B1, Tab 3, Schedule 15)[3]

And, the Commission concluded:

> The Commission Panel establishes a CAPM estimate by …. using an adjusted beta in the range of 0.60 to 0.66.[4]

d) Please see the excerpt from the text book, Roger A. Morin, Phd., New Regulatory Finance, Public Utilities Reports, Inc. (2006) pp. 69-78 at Attachment 1.

In his book, Dr. Morin discusses the various methodologies employed in practice in adjusting the utility beta towards the market mean. In addition to his own work, he cites numerous academic studies that support the tendency of beta to revert towards one over time.

e) Concentric relied upon the Morningstar International Equity Risk Premia Report 2011 for market risk premia data for the period 1970 – 2011; and relied upon the Ibbotson – Canadian Risk Premia over Time Report 2006 for market risk premia data for the period 1936 – 1969. Please see Attachments 2 and 3, respectively.

f) The riskless rate used in calculating the long-horizon equity risk premium in the Morningstar/Ibbotson studies is represented by the income return on Canada's long-term government bond. The income return is calculated from yields provided by the International Monetary Fund International Financial Statistics. The Canadian series is composed of government bond yield issues with original maturity of 10 years or more.

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[3] Ibid, at 54.
[4] Ibid, at 60.

Witnesses: J. Coyne
J. Lieberman
Concentric

g) Concentric confirms that the growth rates (up to 667%), on a market weighted basis, are valid inputs for the forward looking market return model and fairly estimates the return investors may expect on the TSX. Further, the 667% growth rate, referenced in the question, belongs to First Majestic Corporation, a gold and silver mining company, whose earnings between Q32010 and Q32011 nearly tripled.[5] At the other end of the spectrum are companies such as Tahoe Resources, with an earnings growth rate of -59.0%. These are companies traded on the TSX, and fairly represent the spectrum of investment opportunities available to investors as part of the overall market return.

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[5] http://seekingalpha.com/article/309303-first-majestic-corporation-s-net-earnings-increase-176-from-q3-2010?source=yahoo

Witnesses: J. Coyne
J. Lieberman
Concentric

It is interesting to note that beta is a linear function of CV rather than σ, lending further credibility to the use of CV as a valid measure of risk.[2]

Divergence of Opinion as a Risk Measure. One useful indicator of risk is the degree of divergence of opinion among analysts about future earnings. The greater the variation in analysts' earnings or growth forecasts, the greater investor uncertainty on future prospects. Zacks Investment Research compiles individual analysts' earnings forecasts for publicly traded companies, along with long-term earnings growth.[3] The variation in growth forecasts as measured by the standard deviation of individual forecasts provides yet another interesting measure of risk.

3.2 Beta as a Risk Measure

Most, if not all, college-level finance textbooks discuss the pervasive and positive influence of beta on return when discussing the empirical validity of the Capital Asset Pricing Model. See for example Brealey, Myers, and Allen (2006), Brigham and Ehrhardt (2005), and Ross, Westerfield, and Jaffee (2005). The empirical evidence on the importance of beta as an important determinant of return is considerable, although controversial as discussed later.

Before discussing the practical usefulness of beta, it should be pointed out that the use of beta as a risk measure is not equivalent to unequivocal acceptance of the Capital Asset Pricing Model (CAPM). The CAPM is a formal theory of how beta risk affects security prices, and is treated extensively in Chapter 5. Here, beta is used purely as one of several reasonable measures of risk, and its use is not predicated on any formal asset pricing theory. Thus, any controversy associated with the validity of the CAPM is deferred until Chapter 5.

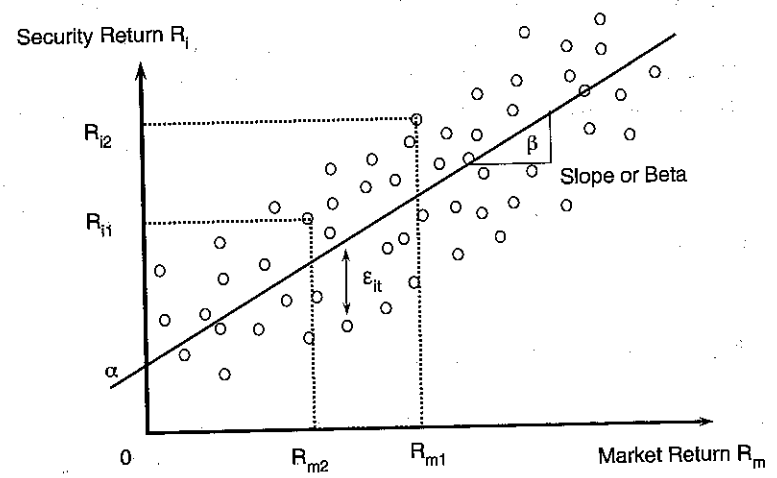
[2] Beta is defined as the covariance between a security's cash flows and that of the aggregate market:

$$\beta = \frac{S_m \, \sigma(x_i) \, \rho_{im}}{S_i \, \sigma(x_m)} \tag{3-1}$$

where S_m refers to the market value of the aggregate index, S_i refers to the company's market value, $\sigma(x_m)$ refers to the standard deviation of aggregate cash flows, and $\sigma(x_i)$ refers to the standard deviation of company cash flows. The above expression is a scaled measure of $\sigma(x_i)/S_i$, the coefficient of variation, with the price-earnings ratio S_m/X_m as the scalar. This is shown in Patterson (1989).

[3] Analysts' forecasts are also available on the Yahoo Finance, Reuters, First Call, and Value Line Web sites.

FIGURE 3-5
THE RELATIONSHIP BETWEEN SECURITY RETURNS AND MARKET RETURNS



Beta measures a security's volatility in relation to that of the market, and is generally computed from a linear regression analysis based on past realized returns over some past time period, as shown in Figure 3-5.

The dependent variable is the security's realized return over a certain time interval, and the independent variable is the corresponding return on some suitable market index, such as the Standard & Poor's 500 Index.

An estimate of the beta coefficient of a stock is obtained through an ordinary least-squares (OLS) regression of the monthly rates of return on the stock, R_{it}, on the monthly return of an aggregate market index, R_{Mt}, typically from the previous five years of stock return data. Beta is simply the estimated slope of the OLS regression line, which has the form:

$$R_{it} = \alpha_1 + \beta_i R_{Mt} + \varepsilon_{it} \qquad (3\text{-}2)$$

Value Line betas are widely available and well-known to investors. Beta estimates are available from several commercial sources including:

1. Value Line Investment Survey
2. Merrill Lynch *Security Risk Evaluation*
3. Bloomberg
4. Yahoo Finance

5. Standard & Poor's
6. Morningstar
7. BARRA

Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. The Value Line data are commercially available on a timely basis to investors in paper format or electronically. Value Line betas are derived from a least-squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the New York Stock Exchange Average over a period of 5 years. In the case of shorter price histories, a smaller time period is used, but 2 years is the minimum. Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00. This necessary adjustment to beta is discussed below.

Practical and Conceptual Difficulties

Computational Issues. Absolute estimates of beta may vary over a wide range when different computational methods are used. The return data, the time period used, its duration, the choice of market index, and whether annual, monthly, or weekly return figures are used will influence the final result.

Ideally, the returns should be total returns, that is, dividends and capital gains. In practice, beta estimates are relatively unaffected if dividends are excluded. Theoretically, market returns should be expressed in terms of total returns on a portfolio of all risky assets. In practice, a broadly based value-weighted market index is used. For example, Merrill Lynch betas use the Standard & Poor's 500 market index, while Value Line betas use the New York Stock Exchange Composite market index. In theory, unless the market index used is the true market index, fully diversified to include all securities in their proportion outstanding, the beta estimate obtained is potentially distorted. Failure to include bonds, Treasury bills, real estate, etc., could lead to a biased beta estimate. But if beta is used as a relative risk ranking device, choice of the market index may not alter the relative rankings of security risk significantly.

To enhance statistical significance, beta should be calculated with return data going as far back as possible. But the company's risk may have changed if the historical period is too long. Weighting the data for this tendency is one possible remedy, but this procedure presupposes some knowledge of how risk changed over time. A frequent compromise is to use a 5-year period with either weekly or monthly returns. Value Line betas are computed based on weekly returns over a 5-year period, whereas Merrill Lynch betas are computed with monthly returns over a 5-year period. In an empirical study of utility betas, Melicher (1979) found that while the beta estimating process differs between Merrill Lynch and Value Line, the beta estimates are reasonably comparable in absolute magnitude. Statman (1981) found a small but significant difference in these estimates of beta. He estimated the following relationship between the two beta estimates:

$$\text{M.L. Beta} = 0.127 + 0.879 \text{ V.L. Beta} \qquad (3\text{-}3)$$

The results are not consistent with perfect equality. Both regression coefficients were significant, and the explanatory significance of the relationship, as measured by the R^2 coefficient, was 0.55. But for betas close to 1.0, the differences were very small. Harrington (1983) examined the betas provided by different investment services and found that, in terms of predicting ensuing betas, the Value Line forecasts exhibited the lowest mean square errors for a sample of utility stocks. Reilly and Wright (1988) confirmed the difference in beta found by Statman. The difference was attributed to the alternative time intervals, that is, weekly versus monthly returns. The size and direction of the effect was a function of a security's market value. In other words, the size of the firm is an important consideration when estimating beta or using a published source. For large utility companies, the bias is small, and for practical purposes, far less than any inherent standard error of estimate or measurement error. Using group (industry) estimates palliates the problem.

When the objective of estimating beta is to ascertain the relative values of beta for different companies, it is reasonable to suppose that the relative ranking of the betas is less sensitive to the time period, length of return interval, and duration of time period, than are the absolute values of beta. For example, the risk ranking of stocks based on Value Line betas, which is calculated using weekly returns, may not differ substantially from the risk ranking based on Merrill Lynch betas, which is calculated using monthly returns.

In addition to choice of time period, duration and market index, measurement error is also a concern. Individual company betas are measured with error. To lessen the significance of measurement errors in estimating betas, proxy groups of companies and/or industry estimates can be used. The empirical finance literature shows that the standard error of estimate of betas is considerably smaller for portfolios than for individual company observations. Betas for groups of securities are more stable and more accurate than betas for individual securities.

Raw Beta Versus Adjusted Beta. The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. Well-known college-level finance textbooks routinely discuss the use of adjusted betas.[4] Several authors have investigated the regression tendency of beta and generally reached similar conclusions. High-beta portfolios have tended to decline over time toward unity, while low-beta portfolios have tended to increase over time toward unity. Blume (1971) examines the stability of beta for all common stocks listed on the NYSE, and finds a tendency for a regression of the betas toward 1.00. He demonstrates that the Value Line adjustment procedure anticipates differences between past and future betas. Chen (1981) also analyzes the variability of beta and suggests the Bayesian adjustment approach used by beta producers to estimate time-varying betas.[5] Ibbotson Associates' annual Valuation Yearbook relies on Bayesian betas as well.

A comprehensive study of beta measurement methodology by Kryzanowski and Jalilvand (1983) concludes that raw unadjusted beta (OLS beta) is one of the poorest beta predictors, and is outperformed by the Merrill Lynch-style Bayesian beta approach. Gombola and Kahl (1990) examine the time-series properties of utility betas and find strong support for the application of adjustment procedures such as the Value Line and Merrill Lynch procedures.

The tendency of true betas not only to vary over time but to move back toward average levels is not surprising. A company whose operations or financing make the risk of its stock divergent from other companies is more likely to move back toward the average than away from it. Such changes in beta values are due to real economic phenomena, not simply to an artifact of overly simple statistical procedures.

Because of this observed regressive tendency, a company's raw unadjusted beta is not the appropriate measure of market risk to use. Current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Historical betas, whether raw or adjusted, are only surrogates for expected beta. The best of the two surrogates is adjusted beta.

There is an additional economic justification for the use of adjusted betas in the case of regulated utilities. Adjusted betas compensate for the tendency of

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4 The recommended use of adjusted betas is widespread in mainstream investment and corporate finance textbooks. See for example: Brigham and Ehrhardt (2005) Chapter 5, page 193–4. Damodaran (2002) pages 186–7. See also the well-known investment textbook by Sharpe and Alexander (1995), Chapter 15, Section 8.1.

5 From a Bayesian statistical framework, and without any information at all on true beta, one would presume a stock's beta in relation to the market to be 1.00. Given a chance to see how the stock moved in relation to the market over some historical period, a modification of this "prior" estimate would seem appropriate. But a sensible "posterior" estimate would likely lie between the two values.

regulated utilities to be extra interest-sensitive relative to industrials.[6] In the same way that bondholders get compensated for inflation through an inflation premium in the interest rate, utility shareholders receive compensation for inflation through an inflation premium in the allowed rate of return. Thus, utility company returns are sensitive to fluctuations in interest rates. Conventional betas do not capture this extra sensitivity to interest rates. This is because the market index typically used in estimating betas is a stocks-only index, such as the S&P 500. A focus on stocks alone distorts the betas of regulated companies. The true risk of regulated utilities relative to other companies is understated because when interest rates change, the stocks of regulated companies react in the same way as bonds do. A nominal interest rate on the face value of a bond offers the same pattern of future cash flows as a nominal return applied on a book value rate base. Empirical studies of utility returns confirm that betas are higher when calculated in a way that captures interest rate sensitivity. The use of adjusted betas compensates for the interest sensitivity of regulated companies.

There is a statistical justification for the use of adjusted betas as well. Statistically, betas are estimated with error. High-estimated betas will tend to have positive error (overestimated) and low-estimated betas will tend to have negative error (underestimated). Therefore, it is necessary to squash the estimated betas in toward 1.00. One way to accomplish this is by measuring the extent to which estimated betas tend to regress toward the mean over time. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. This adjustment, which is commonly performed by investment services such as Value Line, Bloomberg, and Merrill Lynch, uses the formula:

$$\beta_{adjusted} = 1.0 + a\,(\beta_{raw} - 1.0) \qquad (3\text{-}4)$$

where "a" is an estimate of the extent to which estimated betas regress toward the mean based on past data. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% weight to the measured beta and approximately 34% weight to the prior value of 1.0 for each stock, that is, a = 0.66 in the above equation:

$$\begin{aligned}\beta_{adjusted} &= 1.0 + 0.66(\beta_{raw} - 1.0)\\ &= 0.33 + 0.66\,\beta_{raw} \qquad (3\text{-}5)\end{aligned}$$

[6] See Myers, Kolbe, and Tye (1985), Kolbe and Read (1984), and Vilbert (2004) for a full discussion of the sensitivity of utility stocks to interest rates including underlying theory and empirical evidence.

It has been argued that the empirical studies supporting the use of adjusted betas were not performed exclusively on utility stocks and, therefore, are inapplicable to utility companies. This belief is premised on a study by Gombola and Kahl (1990) who showed that there is indeed a tendency of betas to regress towards their mean value for individual stocks. But based on their analysis of utility stocks, the Gombola and Kahl results suggest a tendency for utility betas to regress toward their grand utility mean and not toward the grand average of 1.0.

The difficulty with this argument is that in the mid 1990s to mid 2000s period, the risks of electric utility stocks escalated substantially well after the period of study used in these studies because of restructuring, deregulation, and rising competition and, therefore, the true electric utility betas have escalated toward 1.0. This hypothesis can be verified by examining the beta risk measure of a large sample of electric utilities over the 1992–1997 period. This time period was selected because it precedes the deregulation of the electric utility industry in the U.S. and covers a period over which electric utilities constituted natural monopolies. The beta trend is shown in Figure 3-6. The inescapable trend from the graph is the ascent in the Value Line beta, rising steadily from 0.60 to 0.70 prior to deregulation. The rise in raw beta instead of adjusted beta would be even more dramatic. It is therefore highly improbable that electric utility betas have regressed to some steady-state historical industry average in light of the profound transformation that occurred in the electric utility's risk in the 1995–2005 decade and the changing risk perceptions of investors with respect to the electric utility industry.

For additional evidence as to whether electric utility raw betas tend toward the market average of 1.00 or toward the industry average, Professor Damodaran's

FIGURE 3-6
ELECTRIC UTILITY BETAS, 1992–1997

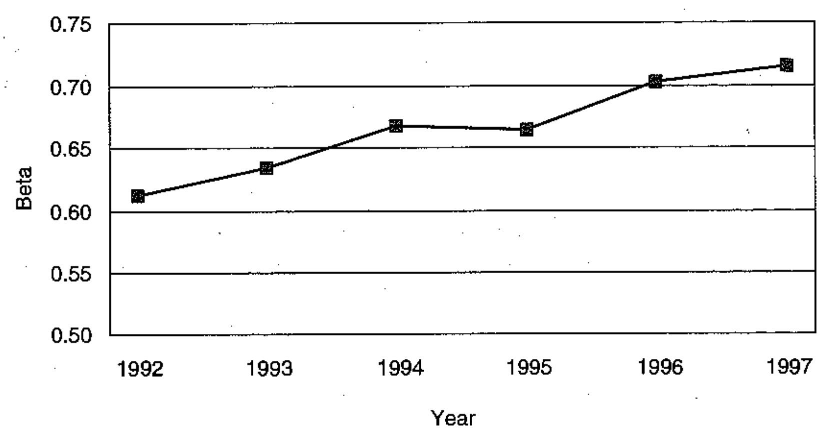
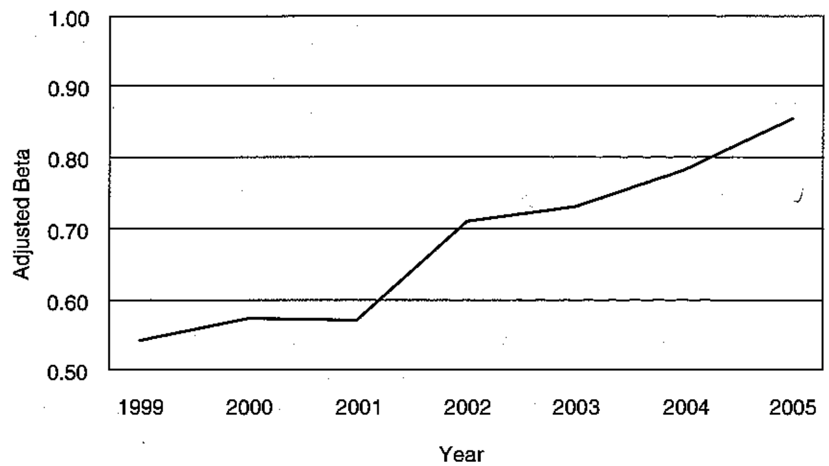


FIGURE 3-7
ELECTRIC UTILITY INDUSTRY
ADJUSTED BETAS 1999–2005



Source: Value Line, Damodaran Web site

extensive Web site reports the following Value Line beta estimates for the electric utility industry over the past five years, shown graphically on Figure 3-7.

The betas shown in the graph are adjusted betas in keeping with investment practices and in keeping with the academic literature on the subject. As noted earlier, adjusted betas reported by *Value Line* give 2/3 weight to the "raw" or calculated beta and 1/3 weight to the market beta of 1.0.[7] Running the process in reverse, the implied raw betas can be calculated and they are shown in the graph shown on Figure 3-8.

The strong upward escalating trend is clear from the graph, showing a steady uninterrupted ascent of raw betas, rather than convergence toward some industry level. Hence the need to employ adjusted betas, as does the majority of commercial beta services and presumably the majority of investors.

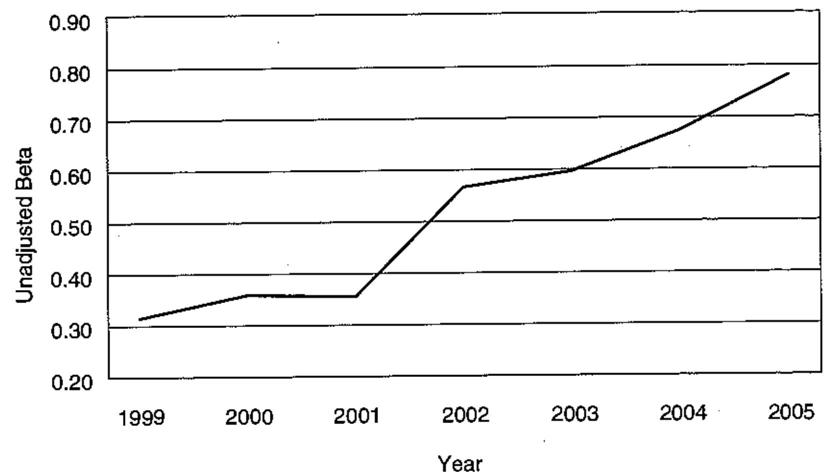
Implied Regulatory Beta

The betas implicit in regulatory ROE decisions are consistent with adjusted betas as well. The CAPM framework can be used to quantify the beta implicit

[7] The standard definition of Adjusted Beta used by Value Line is as follows:

$$\text{Adjusted Beta} = 0.3333 + 0.6666 \times \text{Raw Beta}$$

FIGURE 3-8
ELECTRIC UTILITY INDUSTRY
UNADJUSTED BETAS 1999–2005



Source: Value Line 2005

in the allowed risk premiums for regulated utilities. According to the CAPM, the risk premium is equal to beta times the market risk premium:

$$\text{Risk Premium} = \beta\,(R_M - R_F)$$

Solving for beta, we obtain:

$$\beta = \text{Risk Premium} / (R_M - R_F)$$

The betas implied in hundreds of regulatory decisions for electric utilities in the United States over the period 1996–2005 were examined. Inserting the allowed average risk premium of 5.4% in several hundred ROE decisions over that last decade and a market risk premium of 7.0% in the above equation, the implied beta is 0.77. Using a market risk premium of 6.5%, the implied beta is 0.83. The implied regulatory betas are virtually identical to the adjusted beta estimates reported by Value Line for electric utilities and are clearly inconsistent with raw beta estimates.

To further confirm the desirability of using adjusted betas, one can turn to another measure of risk, namely, relative standard deviations of market returns, which measures total market risk (both diversifiable and non-diversifiable) rather than just non-diversifiable market risk. The upper panel of Table 3-1 reports the standard deviation of returns for the overall U.S. equity market, the electric utility industry overall, a sample of high-quality electric utilities, and all energy utilities (natural gas and electric). The lower panel of the table

TABLE 3-1
RELATIVE STANDARD DEVIATION RISK OF ENERGY UTILITIES

	Standard Deviation Measure of Risk	Median	Mean
1	S & P 500	33.8	39.5
2	Moody's Electric Utilities	28.9	27.3
3	All U.S. Electric Utilities	26.8	28.7
4	Hi-Quality U.S. Electric Utilities	24.3	24.1
5	All U.S. Energy Utilities	26.3	30.8
	Standard Deviation Measure of Risk Relative to Aggregate Equity Market	Median	Mean
6	Moody's Electric Utilities	0.85	0.81
7	All U.S. Electric Utilities	0.79	0.85
8	Hi-Quality U.S. Electric Utilities	0.72	0.71
9	All U.S. Energy Utilities	0.78	0.91
	AVERAGE	**0.79**	**0.82**

Source: Value Line Investment Analyzer 2005

reports the standard deviation of returns of the utility groups relative to the standard deviation of the overall aggregate market. The median is 0.79, suggesting that electric utilities are approximately 0.80 as risky as the overall equity market, confirming the reasonableness of adjusted beta estimates of 0.80 for the electric utility industry in that period.

Beta Stability. Several empirical studies of beta coefficients, notably by Blume (1975) and Levy (1971), have revealed the marked instability of betas over time. Both authors noted a pronounced tendency of betas to regress toward unity, that is for high betas to decline over time and for low betas to increase. Even with the aforementioned beta adjustment procedure, betas may still exhibit substantial instability. If betas are going to be applied to determine the cost of capital through the CAPM, stability of beta is crucial. If betas are not stable, any assessment of cost of capital based on historical beta estimates may not hold true for the future period during which the new allowed rates of return will be in effect. But if beta is going to be used to provide an estimate of the relative risk of various securities, the relative relationships between the betas are likely to be less sensitive to instability than are the absolute values of beta. Grouping utilities (industry estimates) palliates the problem, as the beta of a portfolio exhibits far more stability than the beta of an individual security.

International Equity Risk Premia Report 2011

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International Equity Risk Premia Report 2011

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International Equity Risk Premia Methodology

Introduction

This report measures the equity risk premia for various countries over several time periods. For each country a matrix is provided displaying the risk premia for any starting and ending date. Most of the analysis begins in 1970. We attempt to cover sixteen different countries for both the short- and long-horizon equity risk premia. Availability of data can differ significantly from country to country, and is summarized in the following table:

	Long Horizon ERP Start Date	Short Horizon ERP Start Date
Australia	1970	1970
Austria	1972	1970
Belgium	1970	1970
Canada	1970	1970
Denmark	1970	1970
France	1970	1970*
Germany	1970	1970
Ireland	1988	—
Italy	1970	1978
Japan	1970	1970
Netherlands	1970	—
New Zealand	1988	—
Spain	1979	1976
Switzerland	1970	1981
U.K.	1970	1970
U.S.	1970	1970

* 1986 risk-free rate estimated (France)

Methodology

The equity risk premia presented here are intended to be as comparable as possible from country to country. Although the same calculations are used to derive the equity risk premium for each country, the underlying data available for these calculations may differ and thus have an impact on comparability. Due to inconsistent capital market structures and data availability among foreign capital markets, it is extremely important that each country receive some individual attention. This methodology points out important differences in underlying data as well as the actual equity risk premium calculation.

Calculating the Equity Risk Premium

Equity risk premia can be calculated by subtracting the average income return on a riskless asset from the average stock market total return (measured over the same period as the riskless asset). The arithmetic mean (simple average) annual return for the two components is used in the calculation. Once these averages are computed, the average income return on the riskless asset is subtracted from the average stock market total return to form the estimate of the equity risk premium. For example, if a country had an average stock market return of 12.5 percent and an average income return on its long-term government bond of 8.0 percent, the equity risk premium would be 4.5 percent (12.5 – 8.0).

The income return is used to represent the riskless asset because it is the completely riskless portion of the issues' returns (treasury securities are subject to price risk). That is, unexpected changes in yields will cause capital losses or gains in fixed-income securities. Historical income returns are unbiased estimators of the returns that investors expected. Please note that treasury securities are assumed to be riskless for all countries. Although there is much confidence in the U.S. government's guarantee of U.S. securities, other countries' governmental securities may entail additional default risk. The potential of higher default risk is not taken into account in this report.

To be included in the analysis, a country must have at least five years of quality equity and risk-free return data. Please note that the U.S. equity risk premium is also calculated over the same respective time period as each country's equity risk premium is calculated, but the U.S. data are included for comparison purposes only. In the *2011 Ibbotson® SBBI® Valuation Yearbook*, the U.S. long- and short-horizon equity risk premia are estimated to be 6.7 and 8.2 percent respectively, using data spanning 1926–2010. The results presented here differ considerably from the 1926–2010 period. We recommend using the longest time period for which quality data is available to calculate risk premia. For this reason, we use the longest history available for each of the countries presented in this report.

Both long- and short-horizon equity risk premia are presented when possible. The long-horizon equity risk premium utilizes the appropriate country's long-term government bond income return as the riskless asset. The short-horizon equity risk premium utilizes the appropriate country's cash equivalent rate as the riskless asset. See the sections on long- and short-horizon riskless rates for more detail.

The equity risk premia are also presented both in local currency terms and in U.S. dollars. See the section on currency conversion for more detail.

Market Returns

The stock market returns by country are those given by Morgan Stanley Capital International (MSCI). MSCI Indices are designed to reflect the performance of the entire range of stocks available to investors in each local market. Each stock in the local index is weighted by market capitalization. Data is available from January 1970–present with exceptions noted above. Stocks are chosen for the indices by the following criteria:

1) The MSCI Indices aim for 60% coverage of the total market capitalization for each market.

2) The companies included in the indices replicate the industry composition of each global market.

3) The chosen list of stocks includes a representative sampling of large, medium, and small capitalization companies from each local market, taking into account the stocks' liquidity.

4) Stocks of non-domiciled companies, investment trusts and mutual funds are not eligible for country indices.

5) Companies with restricted float due to dominant shareholders or cross ownership are avoided.

Dividend Reinvestment

For the developed markets, such as the countries in this report, indices with dividends reinvested provide an estimate of total return that would be achieved by reinvesting one-twelfth of the annual yield reported at every month-end. The series with gross dividends reinvested take into account actual dividends before withholding taxes, but exclude special tax credits declared by the companies. The Net of Taxes series are based on the same dividend minus tax credit calculations, but subtract withholding taxes retained at the source for foreigners who do not benefit from a double taxation treaty.

For additional and recently updated information please refer to the MSCI BARRA web page at http://www.MSCIBarra.com.

Long-Horizon Riskless Rate

The riskless rate used in calculating the long-horizon equity risk premium is represented by the income return on each country's long-term government bond. For each country, income return is calculated from yields provided by the International Monetary Fund International Financial Statistics. Although U.S. Treasury securities are thought by most to be completely riskless, since they are backed by the U.S. government, other countries may have some risk of default. The potential for default should be kept in mind when evaluating the final analysis.

These IMF government bond yields have long-term maturities and vary from country to country. Returns are calculated assuming that a single bond is bought at par (i.e., the coupon equals the market yield) at the beginning of each period. The bond is "held" over the period, and "sold" at the end of the period at the then-prevailing market yield. The end-of-period price is calculated as a function of the coupon, yield, and maturity remaining at period end.

The return in excess of yield (capital appreciation) is then derived as the change in price over the period, divided by the beginning-of-period price (i.e., divided by par). The yield is converted to an income return by (dividing it by 12) lagging it one period. Country specific information follows:

Australia: This series is composed of secondary market yields on non-rebate bonds with maturity of 10 years. Yields are calculated before brokerage and on the last business day of the month.

Austria: This series refers to all government bonds issued and not yet redeemed. They are weighted with the share of each bond in the total value of the government bonds in circulation. The data include bonds benefiting from tax privileges under the tax reduction scheme. Beginning January 1985, this series refers to secondary market yields of government bonds with a 10-year maturity. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

Belgium: Beginning September 1963, the data provides yields on government bonds of 5 years or greater. In January 1980, the series changed to secondary market yields of government bonds with a 10-year maturity. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

Canada: This series is composed of government bond yield issues with original maturity of 10 years or more. It is calculated based on an average yield to maturity.

Denmark: From 1970 to 1983, this series used the yield on 5-year government bonds. Beginning June 1983 to present, the series refers to secondary market yields of government bonds with a 10-year maturity. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

France: Through December 1979, the series uses average yield to maturity on public sector bonds with original maturities of more than 5 years. Monthly yields are based on weighted averages of weekly data. From January 1980 to present, the series refers to secondary market yields of government bonds with a 10-year maturity. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

Germany: From 1970 to 1979, the bonds issued by the federal government, the railways, the postal system, the Lander governments, municipalities, specific purpose public associations, and other public associations established under special legislation are used to compose this index. This index is calculated based upon the average yields on all bonds with remaining maturity of more than 3 years, weighted by amount of individual bonds in circulation. On January 1980, the series was changed to comprise of yields on listed federal securities that can be traded on the German Financial Futures and Options Exchange (DTB) with a remaining maturity of 9 and 10 years. This rate is used to measure long-term interests rates for assessing convergence among the European Union member states.

Ireland: From 1970 to July 1988, this series is composed of bond yields on government securities with 15-year maturities. Beginning August 1988, refers to secondary market yields of government bonds with a 10-year maturity This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

Italy: Prior to 1980, the data is comprised of average yields to maturity on bonds with original maturities of 15 to 20 years, issued on behalf of the Treasury by the Consortium of Credit for Public Works. Beginning January 1980, average yields to maturity on bonds with residual maturities between 9 and 10 years. From January 1999 to present, monthly data are arithmetic averages of daily gross yields to maturity of the fixed coupon 10-year Treasury benchmark bond (last issued bond beginning from the date when it becomes the most traded issue among government securities with residual maturities between 9 and10 years), based on prices in the official wholesale market. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

Japan: The series comprises of the arithmetic average yield on newly issued government bonds with 10-year maturity. The monthly series are complied from closing (end-of-month) prices quoted on the Tokyo Stock Exchange.

Netherlands: The series contains secondary market yields on the most recent 10-year government bond. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

New Zealand: Prior to 1987, the data refers to the yield on government bonds. Beginning in January 1987, the series began using the rate on the 5-year 'benchmark' bond, a specific bond selected by the Reserve Bank to provide a representative 5-year government bond rate.

Spain: Prior to 1980, the series is composed on simple monthly average of daily yields on bonds with over 2 years maturity include in the government's Sistema de Anotaciones de Cuenta de Deuda del Estado (SACDE). From 1980 to present, this series refers to secondary market yields of government bonds traded in the book entry system with maturities close to 10 years. This rate is used to measure long-term interest rates for assessing convergence among the European Union member states.

Switzerland: Prior to 1998, the data covered government bonds with maturity of up to 20 years. Annual yields are end-of-period data. Beginning in January 1998, the series contains spot interest rates on government bonds with 10-year maturity.

United Kingdom: This series comprises of theoretical gross redemption bond yields from the Bank of England. The bonds are issued at par with 20 years to maturity.

For additional and recently updated information, please refer to the International Monetary Fund web site at http://www.imf.org.

Short-Horizon Riskless Rate

The riskless rate used in calculating the short-horizon equity risk premium is represented by the cash equivalent rate for the given country. The IMF Cash Equivalents are computed by using lagged yields from the IMF. The IMF yields are short-term instruments, money market rates, Treasury bill rates, discount rates, or short-term government bond yields depending on the country, with generally less than three months to maturity.

The total return is calculated assuming a single bond is bought at par and sold at the end of the period, at the previous month's market yield. The end of period price is calculated solely as a function of the yield. In this instance, the total return is used to represent the riskless rate of return. In general, the total return and income return of these short-term instruments are either the same or very close. Therefore, it is not necessary to use the income return to represent the riskless rate of return.

The formula for computing total returns is:

$$P_1 = \left(1 - \frac{Y_0}{1200}\right) \times 100 \qquad R_1 = \left(\frac{100}{P_1}\right) - 1$$

Where:

Y_0 = Yield at period 0;

P_1 = Price computed for period 1; and,

R_1 = Total Return at period 1.

Country specific information follows:

Australia: From 1970 to May 1981, the short-term rate is the yield on 2-year Treasury bonds. Beginning in June 1981, the series comprised of secondary market yields on non-rebate bonds with maturity of 2 years. From June 1992 to present, the short-term rate refers to non-rebate bonds with maturity of 3 years. Yields are calculated before brokerage and on the last business day of the month.

Austria: Prior to January 1999, the series uses the end of period discount rate of National Bank of Austria's eligible paper. The bank also lent against government and other eligible securities at the Lombard rate, which was usually above the discount rate. Beginning in January 1999, the central bank policy rates were discontinued. From 1999 to present, the 3 month EURIBOR is used.

Belgium: Prior to 1991, the series uses the call money rate. From January 1991 through 1999, the series uses the averages of borrowing and lending rates for three-month interbank transactions. From 1999 to present, the 3 month EURIBOR is used.

Canada: The series is composed of the weighted average of the yields on successful bids for 3-month treasury bills. Monthly data relate to the tender rates of the last Wednesday of the month.

Denmark: This series uses the end of period discount rate.

France: Prior to January 1999, the series contains the monthly average of rates for overnight loans against private bills, based on opening quotations. From 1999 to present, the 3 month EURIBOR is used.

Germany: The series uses money market rates that are calculated based on period averages of 10 daily average quotations for overnight credit.

Italy: This series uses the monthly average yield, before tax, on newly issued 3-month, 6-month, and 12-month treasury bills, weighted by the respective volumes of the 3 maturities.

Japan: The series contains the lending rate for collateral and overnight loans in the Tokyo Call Money Market.

Spain: From 1976 to 1979, this series is composed of the daily money market average rates on interbank operations effected through the Bank of Spain's cable service. From 1980 to July 1987, the discount rate on 3-month treasury bills. Beginning in July 1987, the series began using the discount rate on 1-year Treasury bills.

Switzerland: The series uses the monthly average treasury bill rate of interest on Federal Debt Register Claims.

United Kingdom: This series uses the tender rate of 91-day bills that are allotted in terms of the amount of the discount. The monthly data is composed of weighted averages of Friday data.

For additional and recently updated information, please refer to the International Monetary Fund web site at http://www.imf.org.

Currency Conversion

Risk premia are presented both in local currency terms and in U.S. dollar terms. To convert to U.S. dollars, each annual return is converted at the prevailing exchange rate. An average exchange rate is not applied in this case. Each annual equity return and riskless rate return is converted to U.S. dollars before they are averaged. The exchange rate sources are as follows:

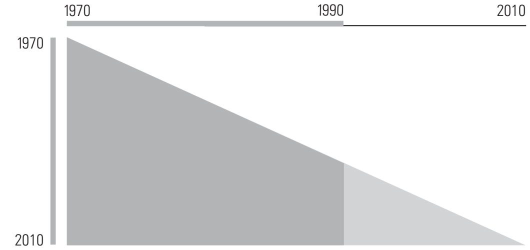
1960–1987: OECD—Main Economic Indicators Historical Statistics (Organization for Economic Cooperation & Development)

1988–present: The Wall Street Journal

Raw data are expressed as a ratio of foreign currency to U.S. Dollar. Ibbotson Associates calculates exchange returns as the monthly percentage change in exchange rates, representing the return to a foreign investor holding non-interest-bearing U.S. currency.

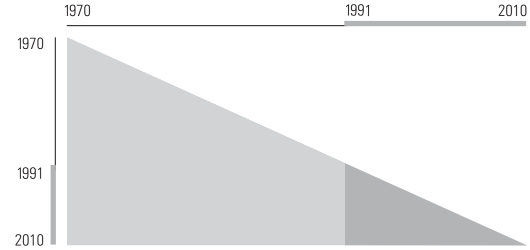
Recent history of all exchange rates is from the Currency Trading section of The Wall Street Journal. These New York foreign exchange selling rates apply to trading among banks in amounts of $1 million and more, as quoted at 3 p.m. Eastern time by Bankers Trust Co., Dow Jones Telerate Inc. and other sources.

Australia Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-25.4																				
1971	-19.8	-14.3																			
1972	-10.1	-2.5	9.4																		
1973	-15.8	-12.6	-11.8	-32.9																	
1974	-19.1	-17.6	-18.7	-32.7	-32.5																
1975	-8.0	-4.5	-2.1	-5.9	7.6	47.7															
1976	-7.7	-4.8	-2.9	-6.0	3.0	20.7	-6.2														
1977	-7.2	-4.6	-3.0	-5.5	1.3	12.6	-4.9	-3.6													
1978	-5.1	-2.6	-0.9	-2.7	3.4	12.4	0.6	4.0	11.6												
1979	-0.6	2.2	4.2	3.5	9.6	18.0	10.6	16.2	26.1	40.5											
1980	2.6	5.4	7.6	7.4	13.2	20.8	15.4	20.8	28.9	37.6	34.7										
1981	-0.3	1.9	3.6	2.9	7.4	13.1	7.3	10.0	13.5	14.1	0.9	-32.9									
1982	-2.3	-0.4	0.9	0.1	3.7	8.2	2.6	4.1	5.6	4.1	-8.0	-29.3	-25.7								
1983	1.9	4.0	5.5	5.2	9.0	13.6	9.3	11.5	14.0	14.5	8.0	-0.8	15.2	56.2							
1984	0.5	2.4	3.7	3.2	6.5	10.4	6.2	7.8	9.4	9.1	2.8	-5.2	4.1	19.0	-18.3						
1985	2.6	4.4	5.8	5.5	8.7	12.5	8.9	10.6	12.4	12.5	7.8	2.5	11.3	23.7	7.4	33.1					
1986	4.4	6.2	7.6	7.5	10.6	14.2	11.1	12.9	14.7	15.1	11.4	7.6	15.7	26.0	16.0	33.1	33.1				
1987	3.5	5.2	6.4	6.2	9.0	12.2	9.2	10.6	12.0	12.1	8.5	4.8	11.1	18.5	9.0	18.1	10.6	-11.8			
1988	3.5	5.1	6.3	6.1	8.7	11.6	8.8	10.1	11.3	11.3	8.0	4.7	10.1	16.1	8.1	14.6	8.5	-3.8	4.1		
1989	3.7	5.2	6.3	6.1	8.5	11.3	8.7	9.8	11.0	10.9	7.9	5.0	9.7	14.8	7.9	13.1	8.1	-0.3	5.5	6.9	
1990	2.2	3.6	4.5	4.3	6.5	8.9	6.3	7.2	8.0	7.7	4.8	1.8	5.6	9.5	2.9	6.4	1.1	-6.9	-5.3	-10.0	-27.0
1991	3.3	4.7	5.6	5.4	7.5	9.9	7.5	8.5	9.3	9.1	6.5	4.0	7.7	11.4	5.8	9.2	5.2	-0.4	2.5	2.0	-0.5
1992	2.7	4.0	4.9	4.7	6.6	8.8	6.5	7.3	8.0	7.8	5.3	2.8	6.1	9.2	4.0	6.8	3.1	-1.9	0.0	-1.0	-3.6
1993	3.9	5.1	6.0	5.9	7.8	9.9	7.8	8.7	9.4	9.3	7.1	4.9	8.1	11.2	6.7	9.4	6.5	2.7	5.1	5.3	4.8
1994	3.2	4.3	5.2	5.0	6.8	8.7	6.7	7.4	8.0	7.8	5.6	3.6	6.4	9.1	4.8	7.1	4.2	0.6	2.3	2.0	1.1
1995	3.3	4.5	5.2	5.1	6.8	8.7	6.7	7.4	8.0	7.8	5.8	3.8	6.5	8.9	5.0	7.1	4.5	1.3	3.0	2.8	2.1
1996	3.3	4.4	5.1	4.9	6.6	8.4	6.5	7.1	7.7	7.5	5.5	3.7	6.2	8.4	4.8	6.7	4.3	1.4	2.9	2.7	2.1
1997	3.3	4.3	5.0	4.9	6.4	8.1	6.3	6.9	7.5	7.3	5.4	3.7	6.0	8.1	4.7	6.4	4.2	1.6	2.9	2.8	2.2
1998	3.4	4.5	5.1	5.0	6.5	8.1	6.4	7.0	7.5	7.3	5.5	3.9	6.1	8.1	4.9	6.5	4.5	2.1	3.3	3.3	2.9
1999	3.5	4.5	5.2	5.0	6.5	8.0	6.4	6.9	7.4	7.2	5.6	4.0	6.1	7.9	4.9	6.5	4.6	2.4	3.6	3.5	3.2
2000	3.4	4.4	5.0	4.9	6.3	7.7	6.2	6.7	7.1	6.9	5.3	3.8	5.8	7.5	4.7	6.1	4.3	2.2	3.3	3.3	2.9
2001	3.5	4.4	5.0	4.9	6.2	7.7	6.1	6.6	7.1	6.9	5.3	3.9	5.8	7.4	4.7	6.1	4.4	2.5	3.5	3.5	3.2
2002	2.9	3.8	4.4	4.2	5.5	6.9	5.4	5.8	6.2	5.9	4.4	3.1	4.8	6.3	3.7	4.9	3.2	1.4	2.3	2.1	1.8
2003	3.1	3.9	4.5	4.3	5.6	6.9	5.4	5.9	6.2	6.0	4.6	3.3	4.9	6.4	3.9	5.1	3.5	1.8	2.6	2.5	2.2
2004	3.6	4.4	5.0	4.9	6.1	7.4	6.0	6.4	6.8	6.6	5.2	4.0	5.6	7.1	4.7	5.9	4.4	2.8	3.7	3.7	3.5
2005	4.0	4.9	5.5	5.3	6.5	7.8	6.5	6.9	7.3	7.1	5.8	4.7	6.2	7.6	5.4	6.6	5.2	3.8	4.6	4.6	4.5
2006	4.4	5.2	5.8	5.7	6.9	8.1	6.8	7.3	7.6	7.5	6.3	5.2	6.7	8.1	6.0	7.1	5.8	4.5	5.3	5.4	5.3
2007	4.6	5.4	5.9	5.8	7.0	8.2	6.9	7.4	7.7	7.6	6.4	5.4	6.9	8.2	6.2	7.2	6.0	4.8	5.6	5.7	5.6
2008	3.4	4.1	4.6	4.5	5.6	6.7	5.4	5.8	6.1	5.9	4.7	3.7	5.0	6.2	4.2	5.1	3.9	2.6	3.3	3.2	3.0
2009	4.1	4.8	5.4	5.2	6.3	7.4	6.2	6.6	6.9	6.8	5.6	4.6	6.0	7.2	5.3	6.2	5.1	3.9	4.6	4.6	4.5
2010	3.9	4.6	5.1	5.0	6.0	7.1	5.9	6.3	6.6	6.4	5.3	4.3	5.6	6.7	4.9	5.8	4.7	3.5	4.2	4.2	4.1

Australia Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
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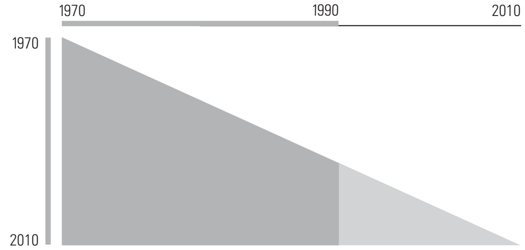
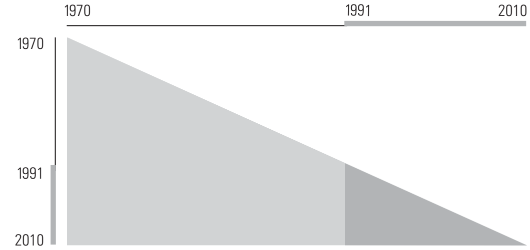
1990																				
1991	26.0																			
1992	8.1	-9.8																		
1993	15.5	10.2	30.2																	
1994	8.1	2.1	8.1	-14.0																
1995	7.9	3.4	7.9	-3.3	7.4															
1996	7.0	3.2	6.4	-1.5	4.8	2.1														
1997	6.4	3.2	5.8	-0.4	4.2	2.6	3.1													
1998	6.6	3.8	6.1	1.3	5.1	4.3	5.5	7.8												
1999	6.5	4.1	6.1	2.1	5.3	4.8	5.6	6.9	6.0											
2000	5.9	3.7	5.4	1.8	4.5	3.9	4.3	4.8	3.2	0.5										
2001	5.9	3.9	5.4	2.3	4.7	4.2	4.6	5.0	4.1	3.2	5.9									
2002	4.2	2.2	3.4	0.4	2.2	1.5	1.3	1.0	-0.7	-2.9	-4.7	-15.2								
2003	4.4	2.6	3.8	1.1	2.8	2.2	2.3	2.1	1.0	-0.3	-0.5	-3.7	7.8							
2004	5.6	4.1	5.2	2.9	4.6	4.3	4.6	4.8	4.3	4.0	4.9	4.6	14.4	21.1						
2005	6.6	5.2	6.4	4.4	6.1	5.9	6.4	6.8	6.6	6.7	8.0	8.5	16.4	20.7	20.3					
2006	7.3	6.1	7.2	5.4	7.1	7.0	7.5	8.0	8.0	8.3	9.6	10.4	16.8	19.8	19.1	17.9				
2007	7.5	6.4	7.4	5.8	7.3	7.3	7.8	8.3	8.3	8.6	9.8	10.4	15.6	17.5	16.3	14.3	10.7			
2008	4.7	3.5	4.3	2.6	3.7	3.5	3.6	3.6	3.2	2.9	3.2	2.8	5.8	5.4	1.5	-4.8	-16.2	-43.1		
2009	6.2	5.1	5.9	4.4	5.7	5.5	5.8	6.0	5.9	5.8	6.4	6.5	9.6	9.9	7.7	4.5	0.0	-5.3	32.5	
2010	5.6	4.5	5.3	3.9	5.0	4.8	5.0	5.2	5.0	4.9	5.3	5.3	7.8	7.8	5.6	2.7	-1.2	-5.1	13.9	-4.8

Australia Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-25.6																				
1971	-17.0	-8.4																			
1972	-5.6	4.3	17.1																		
1973	-9.6	-4.3	-2.3	-21.7																	
1974	-15.7	-13.2	-14.8	-30.7	-39.8																
1975	-6.4	-2.6	-1.1	-7.2	0.0	39.9															
1976	-8.2	-5.3	-4.7	-10.1	-6.3	10.5	-19.0														
1977	-7.0	-4.4	-3.7	-7.9	-4.4	7.4	-8.9	1.2													
1978	-4.9	-2.3	-1.4	-4.5	-1.0	8.7	-1.7	6.9	12.5												
1979	-0.9	1.9	3.2	1.2	5.0	13.9	7.4	16.2	23.8	35.0											
1980	3.2	6.1	7.7	6.5	10.5	18.9	14.7	23.1	30.4	39.4	43.8										
1981	-0.1	2.3	3.3	1.8	4.7	11.1	6.3	11.3	13.9	14.3	4.0	-35.9									
1982	-2.8	-0.9	-0.2	-1.9	0.3	5.3	0.3	3.5	4.0	1.9	-9.2	-35.7	-35.4								
1983	0.5	2.5	3.5	2.2	4.6	9.5	5.7	9.3	10.6	10.2	4.0	-9.2	4.1	43.7							
1984	-1.2	0.6	1.3	-0.1	1.9	6.1	2.3	5.0	5.5	4.4	-1.8	-13.2	-5.6	9.3	-25.0						
1985	-0.5	1.2	1.9	0.7	2.5	6.4	3.0	5.5	6.0	5.1	0.1	-8.6	-1.8	9.4	-7.8	9.5					
1986	1.3	3.0	3.7	2.8	4.6	8.4	5.5	7.9	8.7	8.2	4.4	-2.2	4.5	14.5	4.8	19.7	29.9				
1987	1.0	2.5	3.2	2.3	4.0	7.4	4.7	6.8	7.4	6.8	3.3	-2.5	3.1	10.8	2.6	11.8	12.9	-4.1			
1988	2.1	3.7	4.4	3.6	5.3	8.5	6.1	8.2	8.8	8.4	5.5	0.7	5.9	12.8	6.7	14.6	16.3	9.5	23.1		
1989	2.0	3.4	4.1	3.3	4.9	7.9	5.6	7.5	8.0	7.6	4.8	0.5	5.1	10.8	5.4	11.5	11.9	5.9	11.0	-1.1	
1990	0.5	1.8	2.4	1.6	2.9	5.6	3.3	4.9	5.2	4.6	1.8	-2.4	1.3	5.9	0.5	4.8	3.8	-2.7	-2.2	-14.9	-28.6
1991	1.6	2.9	3.4	2.7	4.1	6.7	4.6	6.2	6.5	6.1	3.6	0.0	3.6	7.9	3.4	7.5	7.2	2.6	4.3	-1.9	-2.3
1992	0.7	1.9	2.4	1.7	2.9	5.3	3.2	4.6	4.9	4.3	1.9	-1.5	1.6	5.3	1.0	4.3	3.5	-0.9	-0.2	-6.1	-7.7
1993	1.9	3.1	3.6	3.0	4.2	6.5	4.6	6.0	6.3	5.9	3.8	0.8	3.8	7.4	3.8	7.0	6.7	3.3	4.6	0.9	1.4
1994	1.7	2.9	3.4	2.7	3.9	6.1	4.3	5.6	5.9	5.4	3.5	0.6	3.4	6.6	3.3	6.1	5.7	2.7	3.7	0.4	0.7
1995	1.8	2.9	3.3	2.7	3.9	5.9	4.2	5.5	5.7	5.3	3.4	0.7	3.4	6.4	3.2	5.8	5.4	2.7	3.6	0.8	1.1
1996	2.1	3.1	3.6	3.0	4.1	6.1	4.5	5.6	5.9	5.5	3.8	1.3	3.8	6.6	3.7	6.1	5.8	3.4	4.2	1.8	2.3
1997	1.4	2.4	2.8	2.3	3.3	5.1	3.6	4.6	4.8	4.4	2.7	0.3	2.5	5.1	2.3	4.4	4.0	1.6	2.2	-0.1	0.0
1998	1.4	2.4	2.8	2.2	3.2	5.0	3.5	4.5	4.6	4.3	2.6	0.3	2.5	4.8	2.3	4.2	3.8	1.6	2.1	0.1	0.2
1999	1.8	2.8	3.2	2.7	3.6	5.3	3.9	4.9	5.1	4.7	3.2	1.0	3.1	5.4	3.0	4.8	4.5	2.5	3.1	1.3	1.5
2000	1.3	2.2	2.6	2.0	2.9	4.6	3.2	4.1	4.2	3.8	2.3	0.3	2.2	4.3	1.9	3.6	3.2	1.3	1.8	0.0	0.1
2001	1.2	2.0	2.4	1.9	2.7	4.3	2.9	3.8	3.9	3.5	2.1	0.1	1.9	3.9	1.7	3.2	2.8	1.0	1.4	-0.3	-0.2
2002	0.9	1.7	2.1	1.6	2.4	3.9	2.6	3.4	3.5	3.1	1.7	-0.2	1.5	3.3	1.2	2.7	2.3	0.5	0.8	-0.7	-0.7
2003	2.2	3.0	3.4	3.0	3.8	5.3	4.1	4.9	5.0	4.7	3.5	1.7	3.4	5.3	3.4	4.9	4.6	3.1	3.6	2.3	2.5
2004	2.9	3.7	4.1	3.7	4.5	6.0	4.8	5.7	5.8	5.6	4.4	2.7	4.4	6.2	4.5	5.9	5.7	4.4	4.9	3.8	4.1
2005	3.2	4.0	4.3	4.0	4.8	6.2	5.1	5.9	6.1	5.8	4.7	3.1	4.8	6.5	4.8	6.2	6.1	4.8	5.3	4.3	4.6
2006	3.8	4.6	5.0	4.6	5.4	6.8	5.8	6.6	6.8	6.6	5.5	4.1	5.7	7.4	5.8	7.2	7.1	5.9	6.5	5.5	5.9
2007	4.3	5.1	5.5	5.2	5.9	7.3	6.3	7.1	7.3	7.1	6.2	4.8	6.3	8.0	6.5	7.9	7.8	6.7	7.3	6.5	6.9
2008	2.8	3.6	3.9	3.5	4.2	5.5	4.5	5.2	5.4	5.1	4.1	2.7	4.1	5.6	4.1	5.3	5.1	4.0	4.4	3.4	3.7
2009	4.4	5.2	5.6	5.2	6.0	7.3	6.3	7.1	7.3	7.1	6.2	4.9	6.3	7.9	6.5	7.8	7.7	6.7	7.2	6.5	6.9
2010	4.5	5.3	5.6	5.3	6.1	7.3	6.4	7.1	7.3	7.2	6.3	5.0	6.4	7.9	6.6	7.8	7.7	6.8	7.3	6.6	6.9

Australia Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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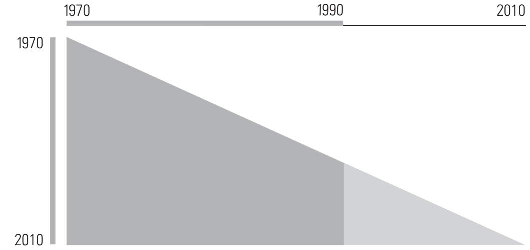
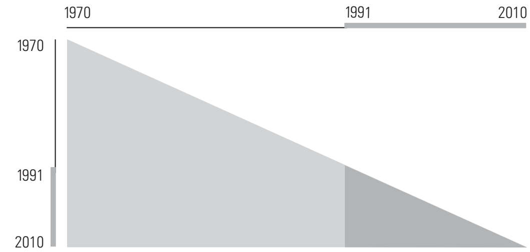
1990																				
1991	23.9																			
1992	2.8	-18.4																		
1993	11.4	5.1	28.6																	
1994	8.1	2.8	13.4	-1.8																
1995	7.1	2.8	9.9	0.6	3.0															
1996	7.4	4.1	9.7	3.4	6.1	9.1														
1997	4.1	0.8	4.6	-1.3	-1.2	-3.2	-15.6													
1998	3.8	0.9	4.1	-0.8	-0.5	-1.7	-7.1	1.5												
1999	4.9	2.5	5.5	1.6	2.3	2.1	-0.2	7.5	13.5											
2000	2.9	0.6	3.0	-0.7	-0.5	-1.2	-3.8	0.2	-0.4	-14.4										
2001	2.4	0.2	2.3	-1.0	-0.9	-1.5	-3.7	-0.7	-1.4	-8.9	-3.3									
2002	1.6	-0.4	1.4	-1.6	-1.6	-2.3	-4.2	-1.9	-2.7	-8.2	-5.0	-6.7								
2003	4.9	3.3	5.3	3.0	3.5	3.6	2.8	5.9	6.7	5.0	11.5	18.9	44.6							
2004	6.4	5.1	7.0	5.1	5.8	6.1	5.7	8.7	9.9	9.2	15.1	21.2	35.2	25.9						
2005	6.8	5.6	7.5	5.7	6.4	6.7	6.5	9.2	10.3	9.8	14.6	19.1	27.7	19.3	12.8					
2006	8.1	7.0	8.9	7.3	8.1	8.6	8.5	11.2	12.4	12.2	16.7	20.7	27.5	21.9	19.8	26.9				
2007	9.0	8.0	9.8	8.5	9.2	9.8	9.8	12.4	13.6	13.6	17.6	21.1	26.6	22.1	20.9	24.9	22.9			
2008	5.5	4.4	5.8	4.3	4.7	4.9	4.5	6.4	6.8	6.1	8.7	10.4	13.2	6.9	2.2	-1.3	-15.4	-53.8		
2009	8.7	7.9	9.4	8.2	8.9	9.3	9.3	11.4	12.3	12.2	15.2	17.5	20.9	17.0	15.2	15.8	12.1	6.8	67.3	
2010	8.7	7.9	9.4	8.2	8.9	9.3	9.3	11.2	12.0	11.9	14.5	16.5	19.4	15.8	14.1	14.3	11.2	7.3	37.8	8.3

Australia Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-25.6																				
1971	-19.8	-13.9																			
1972	-9.7	-1.8	10.3																		
1973	-15.6	-12.2	-11.4	-33.0																	
1974	-19.2	-17.6	-18.8	-33.4	-33.8																
1975	-8.0	-4.4	-2.0	-6.2	7.3	48.3															
1976	-7.6	-4.6	-2.7	-5.9	3.1	21.6	-5.2														
1977	-7.1	-4.4	-2.8	-5.4	1.4	13.2	-4.4	-3.6													
1978	-5.0	-2.4	-0.7	-2.6	3.5	12.8	1.0	4.1	11.7												
1979	-0.5	2.3	4.3	3.4	9.5	18.1	10.6	15.9	25.6	39.4											
1980	2.5	5.3	7.5	7.1	12.9	20.6	15.1	20.2	28.1	36.2	33.0										
1981	-0.6	1.7	3.2	2.4	6.9	12.7	6.7	9.1	12.3	12.5	-1.0	-34.9									
1982	-2.7	-0.8	0.4	-0.5	3.1	7.7	1.9	3.0	4.4	2.5	-9.8	-31.2	-27.5								
1983	1.5	3.6	5.1	4.6	8.4	13.1	8.7	10.6	13.0	13.3	6.7	-2.0	14.4	56.3							
1984	0.3	2.1	3.3	2.8	6.0	10.0	5.7	7.1	8.6	8.1	1.8	-6.0	3.7	19.2	-17.8						
1985	2.2	4.1	5.4	5.0	8.1	12.0	8.3	9.8	11.5	11.5	6.8	1.6	10.7	23.4	6.9	31.7					
1986	4.0	5.8	7.2	6.9	10.0	13.7	10.5	12.1	13.8	14.1	10.5	6.7	15.0	25.7	15.5	32.1	32.5				
1987	3.1	4.7	5.9	5.6	8.4	11.6	8.6	9.8	11.2	11.1	7.5	3.9	10.4	18.0	8.4	17.1	9.8	-12.9			
1988	3.1	4.7	5.8	5.5	8.1	11.1	8.2	9.3	10.5	10.4	7.2	3.9	9.5	15.6	7.5	13.8	7.9	-4.4	4.0		
1989	3.1	4.6	5.7	5.4	7.8	10.6	7.9	8.9	9.9	9.8	6.8	3.9	8.7	13.9	6.8	11.8	6.8	-1.8	3.8	3.5	
1990	1.6	3.0	3.9	3.5	5.7	8.1	5.4	6.2	6.9	6.5	3.6	0.6	4.6	8.6	1.7	5.0	-0.3	-8.5	-7.1	-12.7	-28.8
1991	2.8	4.1	5.0	4.7	6.8	9.2	6.8	7.6	8.4	8.1	5.5	3.0	6.8	10.6	4.9	8.1	4.2	-1.5	1.4	0.5	-1.0
1992	2.3	3.5	4.4	4.1	6.0	8.2	5.9	6.6	7.2	6.9	4.4	2.0	5.4	8.7	3.4	6.0	2.4	-2.6	-0.6	-1.7	-3.5
1993	3.5	4.8	5.6	5.4	7.3	9.5	7.3	8.1	8.8	8.6	6.4	4.4	7.6	10.8	6.3	8.9	6.1	2.3	4.9	5.0	5.4
1994	2.8	4.0	4.7	4.5	6.3	8.3	6.2	6.8	7.4	7.1	5.0	3.0	5.9	8.7	4.3	6.5	3.8	0.2	2.0	1.7	1.3
1995	3.0	4.1	4.9	4.6	6.3	8.3	6.3	6.9	7.4	7.2	5.2	3.3	6.0	8.6	4.7	6.7	4.2	1.0	2.8	2.6	2.5
1996	3.0	4.1	4.8	4.5	6.2	8.0	6.1	6.6	7.2	6.9	5.0	3.3	5.8	8.2	4.5	6.3	4.0	1.2	2.7	2.6	2.4
1997	3.0	4.0	4.7	4.5	6.1	7.8	6.0	6.5	7.0	6.8	4.9	3.3	5.7	7.9	4.4	6.1	4.0	1.4	2.9	2.7	2.6
1998	3.2	4.2	4.9	4.7	6.2	7.8	6.1	6.6	7.1	6.8	5.1	3.6	5.8	7.9	4.7	6.3	4.4	2.0	3.4	3.3	3.3
1999	3.3	4.3	4.9	4.7	6.2	7.8	6.1	6.6	7.0	6.8	5.2	3.7	5.8	7.8	4.8	6.3	4.5	2.3	3.6	3.5	3.5
2000	3.2	4.1	4.8	4.6	6.0	7.5	5.8	6.3	6.7	6.5	4.9	3.5	5.6	7.4	4.5	5.9	4.2	2.2	3.3	3.3	3.3
2001	3.3	4.2	4.8	4.6	6.0	7.4	5.9	6.3	6.7	6.5	5.0	3.7	5.6	7.3	4.6	5.9	4.3	2.5	3.5	3.5	3.5
2002	2.7	3.6	4.2	4.0	5.2	6.6	5.1	5.5	5.9	5.6	4.1	2.8	4.6	6.2	3.6	4.8	3.2	1.4	2.3	2.2	2.1
2003	2.9	3.7	4.3	4.1	5.3	6.7	5.2	5.6	5.9	5.7	4.3	3.1	4.8	6.3	3.8	5.0	3.5	1.8	2.7	2.6	2.5
2004	3.4	4.3	4.8	4.6	5.9	7.2	5.8	6.2	6.5	6.3	5.0	3.8	5.5	7.0	4.7	5.8	4.4	2.9	3.8	3.8	3.8
2005	3.9	4.7	5.3	5.1	6.3	7.6	6.2	6.6	7.0	6.8	5.6	4.5	6.1	7.6	5.4	6.5	5.2	3.8	4.7	4.7	4.8
2006	4.2	5.1	5.6	5.5	6.6	7.9	6.6	7.0	7.4	7.2	6.0	5.0	6.6	8.0	5.9	7.0	5.8	4.5	5.4	5.4	5.6
2007	4.4	5.2	5.7	5.6	6.7	8.0	6.7	7.1	7.5	7.3	6.2	5.2	6.7	8.1	6.1	7.1	6.0	4.7	5.6	5.7	5.8
2008	3.2	3.9	4.4	4.3	5.3	6.5	5.2	5.5	5.8	5.6	4.5	3.4	4.9	6.1	4.1	5.0	3.8	2.5	3.3	3.2	3.2
2009	3.9	4.7	5.2	5.0	6.1	7.2	6.0	6.4	6.7	6.5	5.4	4.5	5.9	7.1	5.2	6.1	5.1	3.9	4.6	4.7	4.7
2010	3.7	4.5	4.9	4.8	5.8	6.9	5.7	6.0	6.3	6.2	5.1	4.2	5.5	6.7	4.8	5.7	4.7	3.5	4.2	4.2	4.3

Australia Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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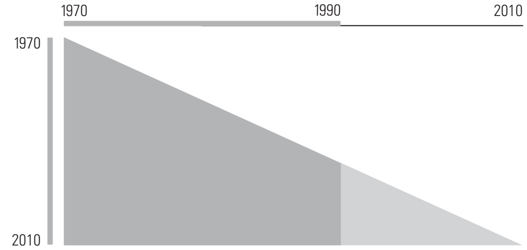
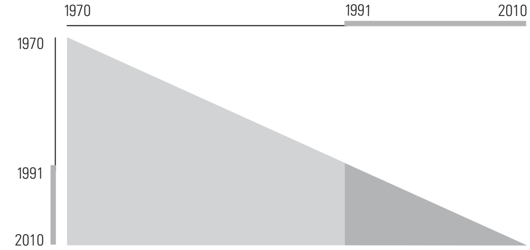
1991	26.9																			
1992	9.2	-8.5																		
1993	16.8	11.8	32.1																	
1994	8.9	2.9	8.5	-15.0																
1995	8.7	4.2	8.4	-3.4	8.1															
1996	7.7	3.8	6.9	-1.5	5.3	2.4														
1997	7.1	3.8	6.3	-0.1	4.8	3.1	3.9													
1998	7.3	4.5	6.7	1.6	5.7	4.9	6.2	8.5												
1999	7.1	4.7	6.5	2.3	5.7	5.1	6.0	7.1	5.7											
2000	6.5	4.2	5.8	2.0	4.9	4.2	4.7	4.9	3.1	0.6										
2001	6.4	4.4	5.8	2.6	5.1	4.6	5.0	5.3	4.2	3.4	6.3									
2002	4.7	2.7	3.8	0.6	2.6	1.8	1.7	1.2	-0.6	-2.7	-4.3	-14.8								
2003	4.9	3.1	4.2	1.4	3.2	2.6	2.6	2.4	1.2	0.0	-0.1	-3.3	8.2							
2004	6.1	4.5	5.6	3.2	5.0	4.7	5.0	5.1	4.5	4.3	5.2	4.9	14.8	21.4						
2005	7.1	5.6	6.7	4.6	6.4	6.2	6.6	7.0	6.8	7.0	8.2	8.7	16.6	20.8	20.2					
2006	7.7	6.4	7.5	5.6	7.3	7.2	7.7	8.2	8.1	8.5	9.8	10.5	16.8	19.7	18.9	17.5				
2007	7.8	6.7	7.7	5.9	7.5	7.5	7.9	8.3	8.3	8.7	9.8	10.4	15.5	17.3	15.9	13.8	10.1			
2008	5.0	3.7	4.5	2.6	3.9	3.6	3.7	3.7	3.2	2.9	3.2	2.8	5.7	5.2	1.1	-5.2	-16.6	-43.2		
2009	6.5	5.3	6.2	4.5	5.8	5.7	5.9	6.1	5.9	5.9	6.5	6.5	9.6	9.8	7.5	4.3	-0.1	-5.2	32.8	
2010	5.9	4.8	5.6	4.0	5.2	5.0	5.2	5.3	5.0	5.0	5.4	5.3	7.8	7.8	5.5	2.6	-1.2	-4.9	14.3	-4.3

Australia Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-25.5																				
1971	-20.2	-14.9																			
1972	-9.8	-1.9	11.0																		
1973	-17.0	-14.1	-13.7	-38.5																	
1974	-19.6	-18.1	-19.2	-34.3	-30.1																
1975	-8.7	-5.3	-3.0	-7.6	7.8	45.8															
1976	-8.1	-5.2	-3.3	-6.8	3.7	20.7	-4.5														
1977	-7.6	-5.0	-3.3	-6.2	1.8	12.5	-4.1	-3.8													
1978	-5.4	-2.9	-1.2	-3.2	3.8	12.3	1.2	4.0	11.8												
1979	-1.1	1.6	3.7	2.7	9.5	17.5	10.4	15.3	24.9	37.9											
1980	2.2	5.0	7.2	6.7	13.2	20.4	15.3	20.3	28.3	36.6	35.3										
1981	-0.7	1.5	3.2	2.3	7.4	12.7	7.2	9.6	12.9	13.3	0.9	-33.4									
1982	-2.5	-0.6	0.7	-0.3	3.9	8.2	2.8	4.0	5.6	4.0	-7.3	-28.6	-23.9								
1983	1.4	3.4	5.0	4.4	8.7	13.0	8.9	10.8	13.3	13.5	7.4	-1.8	13.9	51.8							
1984	0.2	2.0	3.3	2.7	6.4	10.1	6.1	7.4	9.0	8.6	2.7	-5.4	3.9	17.7	-16.3						
1985	1.8	3.6	4.9	4.5	8.1	11.5	8.1	9.5	11.2	11.1	6.6	0.8	9.4	20.5	4.9	26.0					
1986	3.6	5.4	6.7	6.4	9.9	13.2	10.2	11.7	13.4	13.6	10.2	6.0	13.9	23.3	13.8	28.9	31.7				
1987	2.6	4.2	5.4	5.1	8.2	11.1	8.2	9.4	10.7	10.6	7.2	3.1	9.2	15.8	6.9	14.6	8.9	-14.0			
1988	2.7	4.3	5.4	5.0	7.9	10.7	8.0	9.0	10.2	10.0	6.9	3.3	8.6	14.0	6.4	12.1	7.5	-4.6	4.8		
1989	2.7	4.2	5.3	4.9	7.6	10.2	7.6	8.6	9.6	9.4	6.5	3.3	7.9	12.5	5.9	10.4	6.4	-2.0	4.0	3.2	
1990	1.3	2.6	3.5	3.1	5.5	7.8	5.2	5.9	6.7	6.2	3.4	0.2	3.9	7.4	1.0	3.9	-0.5	-8.5	-6.7	-12.5	-28.2
1991	2.4	3.7	4.7	4.3	6.7	8.9	6.6	7.3	8.1	7.8	5.3	2.6	6.2	9.5	4.2	7.1	4.0	-1.5	1.6	0.5	-0.9
1992	2.0	3.2	4.1	3.7	5.9	7.9	5.7	6.4	7.0	6.7	4.3	1.7	4.9	7.8	2.9	5.3	2.3	-2.6	-0.3	-1.5	-3.1
1993	3.2	4.4	5.3	5.1	7.2	9.2	7.2	7.8	8.6	8.4	6.2	4.0	7.1	10.0	5.8	8.2	6.0	2.3	5.0	5.1	5.6
1994	2.4	3.5	4.3	4.0	6.1	7.9	5.9	6.5	7.1	6.8	4.7	2.5	5.3	7.7	3.7	5.7	3.4	-0.1	1.9	1.4	1.0
1995	2.6	3.7	4.5	4.2	6.1	7.9	6.0	6.5	7.1	6.8	4.9	2.9	5.4	7.7	4.0	5.9	3.9	0.8	2.6	2.3	2.2
1996	2.6	3.7	4.4	4.1	6.0	7.6	5.8	6.3	6.9	6.6	4.7	2.8	5.3	7.3	3.9	5.6	3.7	0.9	2.6	2.3	2.2
1997	2.6	3.7	4.4	4.1	5.9	7.4	5.7	6.2	6.7	6.4	4.7	2.9	5.1	7.1	3.9	5.4	3.7	1.2	2.7	2.4	2.3
1998	2.8	3.8	4.5	4.2	6.0	7.5	5.8	6.3	6.7	6.5	4.8	3.1	5.3	7.1	4.1	5.6	4.0	1.7	3.1	3.0	3.0
1999	2.9	3.9	4.6	4.3	6.0	7.4	5.8	6.3	6.7	6.5	4.9	3.3	5.3	7.1	4.3	5.6	4.2	2.1	3.4	3.3	3.3
2000	2.8	3.8	4.4	4.2	5.8	7.1	5.6	6.0	6.4	6.2	4.7	3.2	5.1	6.7	4.0	5.3	3.9	1.9	3.2	3.0	3.0
2001	2.9	3.8	4.5	4.2	5.8	7.1	5.6	6.0	6.4	6.2	4.7	3.3	5.1	6.6	4.1	5.3	4.0	2.2	3.4	3.2	3.2
2002	2.3	3.2	3.8	3.6	5.0	6.3	4.8	5.1	5.5	5.2	3.8	2.4	4.1	5.5	3.1	4.1	2.8	1.0	2.0	1.8	1.7
2003	2.6	3.4	4.0	3.8	5.2	6.4	5.0	5.4	5.7	5.5	4.1	2.8	4.4	5.8	3.5	4.5	3.3	1.6	2.6	2.5	2.4
2004	3.2	4.0	4.6	4.4	5.7	6.9	5.6	6.0	6.3	6.1	4.8	3.6	5.2	6.5	4.3	5.4	4.3	2.8	3.8	3.7	3.7
2005	3.6	4.4	5.0	4.8	6.2	7.3	6.0	6.4	6.8	6.6	5.4	4.2	5.8	7.0	5.0	6.0	5.0	3.6	4.6	4.6	4.7
2006	4.0	4.8	5.4	5.2	6.5	7.7	6.5	6.8	7.2	7.0	5.9	4.8	6.3	7.5	5.6	6.6	5.7	4.4	5.3	5.4	5.5
2007	4.2	5.0	5.5	5.4	6.7	7.8	6.6	7.0	7.3	7.2	6.1	5.0	6.5	7.7	5.8	6.8	5.9	4.7	5.6	5.7	5.8
2008	3.2	3.9	4.4	4.3	5.5	6.5	5.3	5.7	6.0	5.8	4.7	3.6	4.9	6.0	4.2	5.1	4.2	2.9	3.7	3.6	3.7
2009	4.1	4.9	5.4	5.3	6.5	7.5	6.4	6.7	7.1	6.9	5.9	4.9	6.2	7.3	5.6	6.5	5.7	4.6	5.4	5.4	5.6
2010	3.9	4.7	5.2	5.0	6.2	7.2	6.1	6.4	6.7	6.5	5.5	4.5	5.8	6.9	5.2	6.1	5.3	4.2	5.0	5.0	5.1

Australia Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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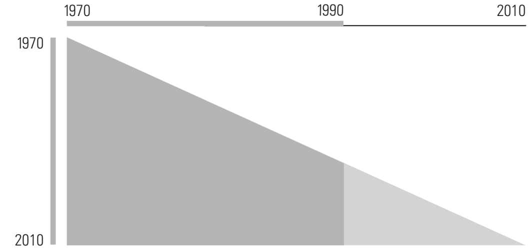
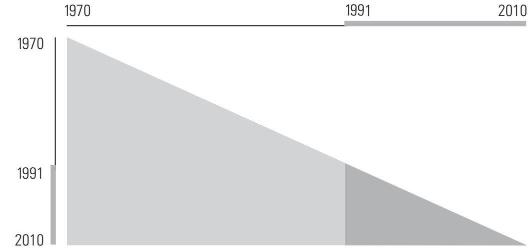
1990																				
1991	26.4																			
1992	9.4	-7.7																		
1993	16.8	12.0	31.7																	
1994	8.3	2.3	7.3	-17.1																
1995	8.2	3.7	7.4	-4.7	7.8															
1996	7.3	3.4	6.2	-2.3	5.2	2.5														
1997	6.7	3.4	5.6	-0.9	4.5	2.9	3.2													
1998	6.9	4.1	6.0	0.9	5.4	4.6	5.6	8.0												
1999	6.8	4.3	6.0	1.8	5.5	5.0	5.8	7.1	6.1											
2000	6.1	3.9	5.3	1.6	4.7	4.1	4.4	4.9	3.3	0.5										
2001	6.1	4.1	5.4	2.1	4.8	4.3	4.7	5.1	4.1	3.1	5.7									
2002	4.2	2.2	3.2	0.0	2.2	1.4	1.2	0.8	-1.0	-3.4	-5.3	-16.3								
2003	4.8	2.9	3.9	1.1	3.2	2.6	2.6	2.5	1.4	0.2	0.1	-2.7	11.0							
2004	6.0	4.4	5.4	3.1	5.1	4.8	5.0	5.3	4.9	4.6	5.6	5.6	16.6	22.2						
2005	6.9	5.5	6.5	4.4	6.3	6.2	6.6	7.0	6.9	7.0	8.3	8.9	17.4	20.6	18.9					
2006	7.6	6.4	7.4	5.5	7.4	7.3	7.8	8.3	8.4	8.7	10.1	10.9	17.7	20.0	18.9	18.9				
2007	7.8	6.7	7.6	5.9	7.7	7.7	8.1	8.6	8.7	9.0	10.2	11.0	16.4	17.8	16.3	15.0	11.2			
2008	5.4	4.2	4.9	3.2	4.6	4.4	4.5	4.6	4.3	4.1	4.6	4.4	7.8	7.2	3.5	-1.7	-11.9	-35.0		
2009	7.3	6.3	7.1	5.6	7.1	7.0	7.4	7.7	7.7	7.8	8.7	9.0	12.6	12.9	11.1	9.1	5.9	3.2	41.5	
2010	6.7	5.7	6.4	4.9	6.3	6.2	6.5	6.7	6.6	6.7	7.3	7.5	10.5	10.4	8.4	6.3	3.2	0.5	18.3	-4.9

Austria Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	NA																				
1971	NA	NA																			
1972	NA	NA	27.0																		
1973	NA	NA	13.0	-0.9																	
1974	NA	NA	5.4	-5.4	-9.9																
1975	NA	NA	2.8	-5.2	-7.4	-4.9															
1976	NA	NA	1.3	-5.1	-6.5	-4.7	-4.6														
1977	NA	NA	-1.2	-6.8	-8.3	-7.8	-9.2	-13.9													
1978	NA	NA	-1.9	-6.7	-7.8	-7.3	-8.1	-9.9	-5.8												
1979	NA	NA	-1.2	-5.2	-6.0	-5.2	-5.2	-5.5	-1.3	3.3											
1980	NA	NA	-2.3	-5.9	-6.6	-6.1	-6.3	-6.7	-4.4	-3.6	-10.5										
1981	NA	NA	-4.0	-7.5	-8.3	-8.1	-8.6	-9.4	-8.3	-9.1	-15.3	-20.1									
1982	NA	NA	-5.0	-8.2	-9.0	-8.9	-9.4	-10.2	-9.5	-10.4	-15.0	-17.2	-14.3								
1983	NA	NA	-4.1	-7.0	-7.6	-7.3	-7.6	-8.0	-7.1	-7.3	-10.0	-9.8	-4.7	5.0							
1984	NA	NA	-3.7	-6.2	-6.7	-6.4	-6.5	-6.8	-5.8	-5.8	-7.6	-6.9	-2.5	3.5	2.0						
1985	NA	NA	4.4	2.6	2.9	4.1	5.0	6.1	8.6	10.6	11.9	16.3	25.4	38.7	55.5	109.1					
1986	NA	NA	4.0	2.4	2.7	3.7	4.5	5.4	7.5	9.2	10.0	13.5	20.2	28.8	36.7	54.1	-0.8				
1987	NA	NA	2.3	0.7	0.8	1.6	2.1	2.7	4.4	5.6	5.8	8.2	12.9	18.3	21.6	28.2	-12.2	-23.7			
1988	NA	NA	2.6	1.0	1.2	2.0	2.5	3.1	4.6	5.7	5.9	8.0	12.0	16.4	18.7	22.8	-5.9	-8.5	6.7		
1989	NA	NA	7.3	6.2	6.6	7.7	8.6	9.6	11.6	13.2	14.2	16.9	21.5	26.7	30.3	35.9	17.6	23.8	47.5	88.3	
1990	NA	NA	6.2	5.1	5.4	6.4	7.1	8.0	9.6	10.9	11.6	13.8	17.6	21.6	24.0	27.6	11.4	14.4	27.1	37.3	-13.8
1991	NA	NA	4.9	3.8	4.1	4.9	5.5	6.2	7.6	8.6	9.1	10.8	13.9	17.1	18.6	21.0	6.3	7.7	15.5	18.4	-16.5
1992	NA	NA	4.1	3.0	3.2	3.9	4.4	5.0	6.2	7.1	7.4	8.9	11.5	14.1	15.1	16.7	3.5	4.2	9.8	10.6	-15.3
1993	NA	NA	5.3	4.3	4.5	5.3	5.9	6.5	7.8	8.7	9.0	10.5	13.1	15.6	16.6	18.3	6.9	8.0	13.3	14.6	-3.8
1994	NA	NA	4.1	3.1	3.3	3.9	4.4	4.9	6.0	6.7	6.9	8.2	10.4	12.4	13.1	14.2	3.7	4.2	8.2	8.5	-7.5
1995	NA	NA	3.1	2.1	2.2	2.8	3.2	3.6	4.6	5.2	5.3	6.4	8.3	10.0	10.4	11.2	1.4	1.6	4.8	4.5	-9.5
1996	NA	NA	3.3	2.3	2.4	3.0	3.4	3.8	4.7	5.3	5.4	6.4	8.1	9.7	10.1	10.8	1.8	2.1	5.0	4.8	-7.2
1997	NA	NA	3.6	2.7	2.9	3.4	3.8	4.2	5.1	5.7	5.8	6.8	8.5	10.0	10.3	11.0	2.8	3.1	5.8	5.7	-4.6
1998	NA	NA	3.1	2.2	2.3	2.8	3.1	3.5	4.3	4.8	4.9	5.7	7.3	8.6	8.9	9.4	1.7	1.9	4.2	4.0	-5.4
1999	NA	NA	3.1	2.2	2.3	2.8	3.1	3.4	4.2	4.7	4.8	5.6	7.0	8.3	8.5	8.9	1.7	1.9	4.1	3.8	-4.6
2000	NA	NA	2.6	1.7	1.8	2.3	2.5	2.8	3.6	4.0	4.0	4.8	6.1	7.2	7.3	7.7	0.9	1.0	2.9	2.6	-5.2
2001	NA	NA	2.3	1.5	1.6	2.0	2.3	2.5	3.2	3.6	3.6	4.3	5.5	6.6	6.6	6.9	0.5	0.6	2.4	2.0	-5.2
2002	NA	NA	2.1	1.2	1.3	1.7	2.0	2.2	2.9	3.2	3.2	3.9	5.0	6.0	6.0	6.2	0.2	0.2	1.8	1.5	-5.2
2003	NA	NA	2.9	2.1	2.2	2.6	2.9	3.1	3.8	4.2	4.2	4.9	6.0	7.0	7.1	7.3	1.7	1.8	3.4	3.2	-2.9
2004	NA	NA	4.5	3.8	3.9	4.4	4.7	5.0	5.7	6.2	6.3	7.0	8.1	9.2	9.4	9.7	4.5	4.8	6.5	6.5	1.0
2005	NA	NA	5.5	4.9	5.1	5.5	5.9	6.2	7.0	7.4	7.6	8.3	9.5	10.5	10.8	11.2	6.3	6.7	8.4	8.5	3.5
2006	NA	NA	5.9	5.3	5.5	6.0	6.3	6.7	7.4	7.9	8.0	8.7	9.9	10.9	11.2	11.6	6.9	7.3	8.9	9.1	4.4
2007	NA	NA	5.4	4.8	5.0	5.4	5.8	6.1	6.8	7.2	7.3	8.0	9.1	10.0	10.2	10.6	6.1	6.4	7.9	8.0	3.5
2008	NA	NA	3.4	2.7	2.8	3.2	3.4	3.7	4.2	4.6	4.6	5.2	6.1	6.9	7.0	7.2	2.7	2.9	4.2	4.0	-0.4
2009	NA	NA	4.2	3.6	3.7	4.1	4.4	4.7	5.3	5.6	5.7	6.2	7.2	8.0	8.1	8.3	4.1	4.4	5.6	5.6	1.4
2010	NA	NA	4.5	3.9	4.0	4.4	4.7	5.0	5.5	5.9	6.0	6.5	7.5	8.2	8.4	8.6	4.6	4.8	6.0	6.0	2.1

Austria Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
1972																				
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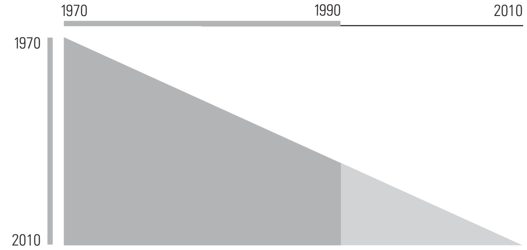
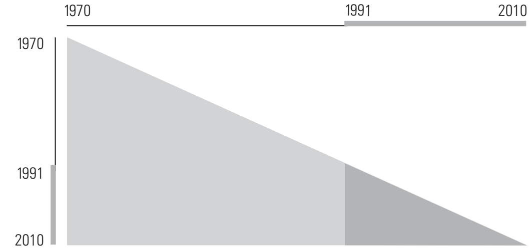
1991	-19.2																			
1992	-16.1	-13.0																		
1993	-0.5	8.9	30.8																	
1994	-5.9	-1.5	4.2	-22.4																
1995	-8.6	-5.9	-3.6	-20.8	-19.2															
1996	-6.1	-3.5	-1.1	-11.7	-6.4	6.5														
1997	-3.3	-0.7	1.8	-5.5	0.2	9.8	13.2													
1998	-4.4	-2.3	-0.5	-6.7	-2.8	2.7	0.8	-11.7												
1999	-3.6	-1.6	0.0	-5.2	-1.7	2.7	1.4	-4.5	2.6											
2000	-4.3	-2.7	-1.4	-6.0	-3.2	-0.1	-1.7	-6.7	-4.2	-10.9										
2001	-4.4	-2.9	-1.8	-5.9	-3.5	-0.9	-2.4	-6.3	-4.4	-8.0	-5.0									
2002	-4.5	-3.1	-2.2	-5.8	-3.7	-1.5	-2.9	-6.1	-4.7	-7.1	-5.2	-5.5								
2003	-2.1	-0.6	0.5	-2.5	-0.3	2.0	1.4	-0.6	1.6	1.4	5.5	10.8	27.0							
2004	2.1	3.7	5.1	2.8	5.3	8.0	8.2	7.5	10.6	12.2	18.0	25.7	41.3	55.6						
2005	4.6	6.3	7.8	5.9	8.5	11.3	11.8	11.6	15.0	17.0	22.6	29.5	41.2	48.2	40.8					
2006	5.5	7.2	8.6	6.9	9.4	12.0	12.5	12.4	15.5	17.3	22.0	27.4	35.6	38.5	29.9	19.0				
2007	4.5	6.0	7.3	5.6	7.8	10.0	10.3	10.0	12.5	13.7	17.2	20.9	26.2	26.0	16.1	3.8	-11.5			
2008	0.3	1.5	2.4	0.5	2.1	3.8	3.6	2.7	4.1	4.3	6.2	7.8	10.0	6.6	-5.7	-21.1	-41.2	-71.0		
2009	2.2	3.4	4.4	2.8	4.4	6.1	6.1	5.5	7.1	7.5	9.5	11.4	13.8	11.6	2.7	-6.8	-15.4	-17.3	36.4	
2010	2.9	4.0	5.0	3.5	5.1	6.7	6.7	6.2	7.7	8.2	10.1	11.8	13.9	12.1	4.8	-2.4	-7.7	-6.5	25.7	15.1

Austria Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	NA																				
1971	NA	NA																			
1972	NA	NA	30.1																		
1973	NA	NA	23.0	15.9																	
1974	NA	NA	16.8	10.1	4.3																
1975	NA	NA	9.5	2.7	-3.9	-12.1															
1976	NA	NA	8.7	3.4	-0.8	-3.3	5.5														
1977	NA	NA	6.6	2.0	-1.5	-3.5	0.8	-3.8													
1978	NA	NA	6.5	2.6	-0.1	-1.2	2.5	1.0	5.8												
1979	NA	NA	7.1	3.8	1.8	1.3	4.6	4.3	8.4	11.0											
1980	NA	NA	4.0	0.8	-1.4	-2.3	-0.4	-1.8	-1.2	-4.6	-20.2										
1981	NA	NA	0.7	-2.6	-4.9	-6.2	-5.2	-7.3	-8.2	-12.9	-24.8	-29.3									
1982	NA	NA	-1.4	-4.5	-6.8	-8.2	-7.6	-9.8	-11.0	-15.2	-23.9	-25.8	-22.2								
1983	NA	NA	-2.0	-4.9	-7.0	-8.2	-7.8	-9.7	-10.6	-13.9	-20.1	-20.1	-15.5	-8.8							
1984	NA	NA	-2.7	-5.4	-7.4	-8.6	-8.2	-9.9	-10.7	-13.5	-18.4	-17.9	-14.1	-10.1	-11.4						
1985	NA	NA	9.4	7.8	7.2	7.4	9.4	9.8	11.5	12.3	12.6	19.1	31.2	49.0	77.9	167.2					
1986	NA	NA	10.5	9.1	8.6	8.9	10.9	11.4	13.1	14.0	14.4	20.2	30.1	43.2	60.5	96.5	25.7				
1987	NA	NA	9.5	8.1	7.5	7.8	9.4	9.8	11.1	11.7	11.8	16.4	24.0	33.3	43.8	62.2	9.7	-6.3			
1988	NA	NA	8.6	7.3	6.7	6.9	8.3	8.6	9.7	10.1	10.0	13.7	19.9	26.9	34.0	45.4	4.8	-5.7	-5.0		
1989	NA	NA	13.6	12.6	12.4	12.9	14.7	15.4	17.0	18.0	18.7	23.1	29.6	37.0	44.7	55.9	28.0	28.8	46.3	97.7	
1990	NA	NA	12.7	11.7	11.5	11.9	13.6	14.1	15.5	16.3	16.8	20.5	26.0	32.1	37.9	46.1	21.9	21.0	30.0	47.6	-2.5
1991	NA	NA	11.1	10.1	9.7	10.0	11.4	11.8	12.9	13.5	13.7	16.8	21.4	26.2	30.6	36.6	14.9	12.7	17.4	24.9	-11.5
1992	NA	NA	9.7	8.6	8.3	8.5	9.7	10.0	10.9	11.2	11.3	13.9	17.8	21.8	25.2	29.8	10.1	7.6	10.3	14.2	-13.7
1993	NA	NA	10.2	9.3	8.9	9.2	10.4	10.7	11.6	11.9	12.0	14.5	18.1	21.8	24.9	28.9	11.6	9.6	12.2	15.7	-4.8
1994	NA	NA	9.2	8.2	7.9	8.1	9.1	9.3	10.1	10.4	10.3	12.5	15.7	18.9	21.4	24.7	8.8	6.7	8.6	10.9	-6.5
1995	NA	NA	8.3	7.3	7.0	7.1	8.0	8.2	8.8	9.0	8.9	10.8	13.7	16.5	18.6	21.3	6.7	4.6	6.0	7.5	-7.5
1996	NA	NA	7.9	7.0	6.6	6.7	7.6	7.7	8.3	8.5	8.3	10.1	12.7	15.2	17.1	19.4	6.0	4.0	5.2	6.5	-6.6
1997	NA	NA	7.5	6.6	6.2	6.3	7.1	7.2	7.8	7.9	7.7	9.3	11.7	14.0	15.6	17.7	5.3	3.4	4.4	5.4	-6.1
1998	NA	NA	7.1	6.2	5.8	5.8	6.6	6.7	7.2	7.2	7.0	8.6	10.8	12.8	14.3	16.1	4.5	2.7	3.5	4.4	-6.0
1999	NA	NA	6.4	5.5	5.1	5.1	5.8	5.8	6.3	6.3	6.1	7.4	9.5	11.4	12.6	14.2	3.3	1.6	2.2	2.9	-6.6
2000	NA	NA	5.6	4.7	4.3	4.3	4.9	4.9	5.3	5.3	5.0	6.2	8.1	9.8	10.9	12.3	2.0	0.3	0.8	1.2	-7.5
2001	NA	NA	5.0	4.2	3.8	3.7	4.4	4.3	4.6	4.6	4.3	5.5	7.2	8.8	9.7	11.0	1.2	-0.4	0.0	0.4	-7.7
2002	NA	NA	5.3	4.4	4.0	4.0	4.6	4.6	4.9	4.9	4.6	5.7	7.4	8.9	9.8	11.0	1.8	0.3	0.8	1.2	-6.2
2003	NA	NA	6.7	6.0	5.7	5.7	6.3	6.4	6.8	6.8	6.6	7.8	9.5	11.0	12.0	13.2	4.6	3.4	4.0	4.6	-2.0
2004	NA	NA	8.6	7.9	7.7	7.8	8.5	8.6	9.0	9.1	9.1	10.3	12.0	13.6	14.6	15.9	8.0	7.0	7.8	8.6	2.6
2005	NA	NA	9.0	8.3	8.1	8.2	8.9	9.0	9.5	9.6	9.6	10.8	12.4	13.9	15.0	16.2	8.7	7.8	8.6	9.4	3.8
2006	NA	NA	9.7	9.1	8.9	9.0	9.7	9.8	10.3	10.5	10.4	11.6	13.3	14.7	15.8	17.0	9.8	9.0	9.9	10.7	5.6
2007	NA	NA	9.4	8.8	8.5	8.7	9.3	9.4	9.9	10.0	10.0	11.1	12.7	14.1	15.0	16.2	9.3	8.5	9.3	10.0	5.1
2008	NA	NA	7.1	6.5	6.2	6.3	6.9	6.9	7.2	7.3	7.2	8.1	9.5	10.7	11.5	12.5	5.8	4.8	5.4	5.9	1.1
2009	NA	NA	8.0	7.4	7.2	7.3	7.8	7.9	8.3	8.4	8.3	9.3	10.6	11.9	12.7	13.6	7.2	6.4	7.0	7.6	3.0
2010	NA	NA	8.0	7.4	7.2	7.3	7.8	7.9	8.3	8.3	8.3	9.2	10.5	11.7	12.5	13.4	7.2	6.5	7.0	7.6	3.3

Austria Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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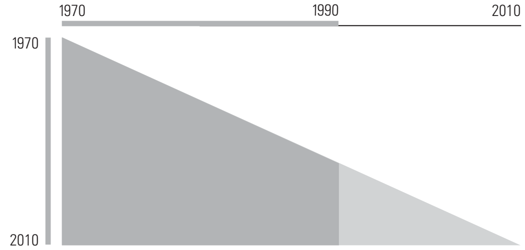
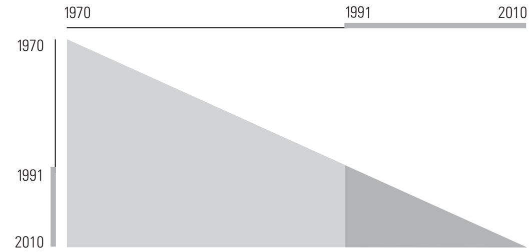
1991	-20.4																			
1992	-19.2	-18.1																		
1993	-5.6	1.9	21.8																	
1994	-7.5	-3.2	4.3	-13.3																
1995	-8.5	-5.5	-1.3	-12.9	-12.5															
1996	-7.2	-4.6	-1.2	-8.9	-6.8	-1.0														
1997	-6.6	-4.3	-1.6	-7.5	-5.5	-2.0	-3.0													
1998	-6.4	-4.4	-2.1	-6.9	-5.3	-2.9	-3.8	-4.6												
1999	-7.1	-5.4	-3.6	-7.8	-6.7	-5.3	-6.7	-8.6	-12.5											
2000	-8.0	-6.6	-5.2	-9.1	-8.4	-7.5	-9.2	-11.2	-14.5	-16.5										
2001	-8.2	-7.0	-5.7	-9.2	-8.6	-7.9	-9.3	-10.9	-13.0	-13.2	-9.9									
2002	-6.6	-5.3	-4.0	-6.9	-6.1	-5.2	-5.9	-6.4	-6.9	-5.0	0.8	11.4								
2003	-2.0	-0.5	1.1	-0.9	0.4	2.1	2.5	3.4	5.0	9.4	18.1	32.1	52.7							
2004	3.0	4.8	6.7	5.3	7.2	9.4	10.7	12.6	15.5	21.1	30.5	43.9	60.2	67.7						
2005	4.3	6.0	7.9	6.7	8.5	10.6	11.9	13.8	16.4	21.3	28.8	38.5	47.5	44.9	22.2					
2006	6.1	7.8	9.7	8.7	10.6	12.7	14.0	15.9	18.5	23.0	29.5	37.4	43.9	41.0	27.6	33.1				
2007	5.6	7.2	8.9	8.0	9.6	11.5	12.6	14.2	16.3	19.8	25.0	30.9	34.8	30.3	17.8	15.6	-1.9			
2008	1.3	2.5	3.8	2.6	3.8	5.0	5.5	6.3	7.4	9.6	12.9	16.1	16.9	9.7	-4.8	-13.7	-37.1	-72.4		
2009	3.3	4.7	6.0	5.0	6.2	7.6	8.2	9.2	10.4	12.7	16.0	19.2	20.3	14.9	4.3	-0.1	-11.2	-15.8	40.8	
2010	3.6	4.8	6.1	5.2	6.3	7.6	8.2	9.0	10.2	12.3	15.1	17.9	18.7	13.9	4.9	1.4	-6.5	-8.0	24.2	7.6

Austria Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	6.3																				
1971	0.1	-6.2																			
1972	9.8	11.5	29.3																		
1973	7.7	8.1	15.3	1.3																	
1974	4.7	4.3	7.8	-2.9	-7.0																
1975	3.7	3.2	5.6	-2.4	-4.2	-1.3															
1976	3.2	2.7	4.4	-1.8	-2.8	-0.7	-0.1														
1977	1.5	0.8	2.0	-3.5	-4.6	-3.9	-5.1	-10.2													
1978	1.1	0.4	1.4	-3.3	-4.2	-3.5	-4.2	-6.2	-2.3												
1979	1.7	1.2	2.1	-1.8	-2.3	-1.3	-1.3	-1.7	2.5	7.3											
1980	0.8	0.2	0.9	-2.6	-3.1	-2.5	-2.7	-3.4	-1.1	-0.6	-8.4										
1981	-0.7	-1.3	-0.9	-4.2	-4.9	-4.6	-5.1	-6.1	-5.1	-6.1	-12.8	-17.1									
1982	-1.5	-2.1	-1.8	-4.9	-5.6	-5.4	-5.9	-6.9	-6.3	-7.3	-12.1	-14.0	-10.8								
1983	-0.7	-1.2	-0.8	-3.6	-4.1	-3.7	-4.0	-4.6	-3.7	-3.9	-6.7	-6.2	-0.7	9.4							
1984	-0.3	-0.8	-0.3	-2.8	-3.2	-2.8	-3.0	-3.3	-2.3	-2.3	-4.3	-3.2	1.4	7.5	5.6						
1985	6.8	6.8	7.7	6.1	6.5	7.7	8.6	9.6	12.0	14.1	15.2	19.9	29.2	42.5	59.1	112.6					
1986	6.5	6.5	7.4	5.8	6.2	7.3	8.1	8.9	11.0	12.6	13.4	17.0	23.9	32.6	40.3	57.6	2.6				
1987	5.1	5.0	5.7	4.1	4.3	5.2	5.7	6.2	7.9	9.0	9.2	11.8	16.6	22.0	25.2	31.7	-8.7	-20.0			
1988	5.3	5.3	5.9	4.5	4.7	5.5	6.1	6.6	8.1	9.1	9.3	11.6	15.7	20.1	22.2	26.3	-2.4	-4.9	10.2		
1989	9.5	9.7	10.6	9.5	10.0	11.1	12.0	13.0	14.9	16.5	17.4	20.2	24.9	30.0	33.5	39.0	20.6	26.6	50.0	89.8	
1990	8.5	8.6	9.4	8.3	8.7	9.7	10.4	11.2	12.8	14.1	14.7	17.0	20.8	24.7	26.9	30.5	14.0	16.9	29.2	38.7	-12.3
1991	7.3	7.4	8.0	6.9	7.2	8.1	8.6	9.2	10.6	11.6	12.0	13.8	16.9	20.0	21.3	23.6	8.7	9.9	17.4	19.9	-15.1
1992	6.4	6.4	7.0	5.9	6.2	6.9	7.4	7.8	9.0	9.8	10.0	11.6	14.2	16.7	17.5	19.0	5.6	6.1	11.3	11.6	-14.4
1993	7.5	7.5	8.1	7.1	7.4	8.2	8.7	9.2	10.4	11.3	11.6	13.1	15.6	18.0	18.9	20.3	8.8	9.7	14.7	15.6	-3.0
1994	6.3	6.3	6.9	5.9	6.1	6.7	7.1	7.5	8.6	9.3	9.4	10.7	12.8	14.8	15.3	16.2	5.5	5.9	9.6	9.5	-6.6
1995	5.5	5.4	5.9	4.9	5.1	5.6	6.0	6.3	7.2	7.8	7.8	8.9	10.8	12.4	12.7	13.3	3.4	3.5	6.4	5.9	-8.1
1996	5.6	5.6	6.1	5.1	5.3	5.9	6.2	6.5	7.4	7.9	8.0	9.0	10.7	12.3	12.5	13.1	4.0	4.2	6.8	6.4	-5.5
1997	6.0	6.0	6.5	5.6	5.8	6.3	6.7	7.0	7.8	8.4	8.4	9.4	11.1	12.5	12.8	13.3	5.1	5.3	7.8	7.5	-2.7
1998	5.5	5.5	5.9	5.0	5.2	5.7	6.0	6.3	7.0	7.5	7.5	8.4	9.9	11.2	11.3	11.7	4.0	4.1	6.3	5.9	-3.5
1999	5.5	5.4	5.8	5.0	5.1	5.6	5.9	6.2	6.9	7.3	7.3	8.2	9.6	10.8	10.9	11.2	4.0	4.1	6.1	5.7	-2.7
2000	5.0	4.9	5.3	4.4	4.6	5.0	5.3	5.5	6.2	6.6	6.5	7.3	8.5	9.6	9.6	9.9	3.0	3.1	4.8	4.4	-3.4
2001	4.7	4.6	5.0	4.1	4.2	4.7	4.9	5.1	5.7	6.1	6.0	6.7	7.9	8.9	8.9	9.0	2.6	2.6	4.2	3.7	-3.4
2002	4.4	4.4	4.7	3.9	4.0	4.4	4.6	4.7	5.3	5.7	5.6	6.2	7.3	8.2	8.2	8.3	2.2	2.2	3.7	3.2	-3.5
2003	5.1	5.1	5.5	4.7	4.8	5.2	5.4	5.6	6.3	6.6	6.6	7.2	8.3	9.2	9.2	9.4	3.7	3.7	5.2	4.9	-1.2
2004	6.6	6.7	7.0	6.3	6.5	7.0	7.2	7.5	8.2	8.6	8.6	9.3	10.5	11.4	11.5	11.8	6.5	6.7	8.3	8.2	2.8
2005	7.6	7.7	8.1	7.4	7.6	8.1	8.4	8.7	9.4	9.8	9.9	10.6	11.8	12.8	12.9	13.3	8.3	8.6	10.2	10.2	5.2
2006	8.0	8.0	8.4	7.8	8.0	8.5	8.8	9.1	9.7	10.2	10.3	11.0	12.1	13.1	13.2	13.6	8.9	9.2	10.7	10.7	6.1
2007	7.4	7.5	7.9	7.2	7.4	7.9	8.1	8.4	9.0	9.4	9.5	10.2	11.2	12.1	12.2	12.5	7.9	8.2	9.6	9.6	5.1
2008	5.4	5.4	5.7	5.1	5.2	5.5	5.8	5.9	6.5	6.7	6.7	7.3	8.2	8.9	8.9	9.0	4.5	4.6	5.8	5.6	1.1
2009	6.3	6.3	6.6	6.0	6.1	6.5	6.7	6.9	7.5	7.8	7.8	8.4	9.3	10.0	10.0	10.2	6.0	6.1	7.3	7.2	3.0
2010	6.6	6.6	6.9	6.3	6.4	6.8	7.0	7.3	7.8	8.1	8.1	8.7	9.6	10.3	10.3	10.5	6.4	6.6	7.7	7.6	3.7

Austria Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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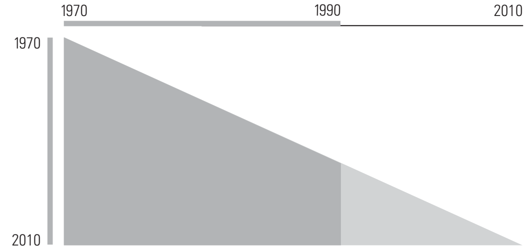
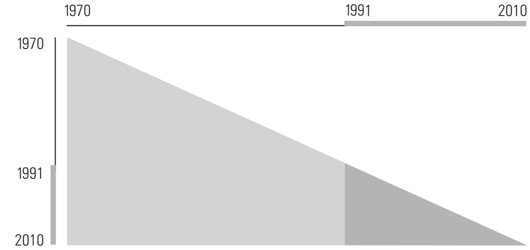
1991	-17.9																			
1992	-15.5	-13.1																		
1993	0.1	9.1	31.3																	
1994	-5.1	-0.9	5.3	-20.8																
1995	-7.2	-4.6	-1.8	-18.3	-15.8															
1996	-4.3	-1.6	1.2	-8.8	-2.8	10.2														
1997	-1.4	1.4	4.3	-2.5	3.6	13.3	16.5													
1998	-2.3	-0.1	2.0	-3.8	0.4	5.8	3.6	-9.2												
1999	-1.6	0.4	2.3	-2.5	1.1	5.4	3.8	-2.6	4.0											
2000	-2.5	-0.8	0.8	-3.6	-0.7	2.3	0.4	-5.0	-2.9	-9.8										
2001	-2.6	-1.1	0.2	-3.7	-1.2	1.2	-0.6	-4.9	-3.4	-7.1	-4.4									
2002	-2.7	-1.4	-0.2	-3.7	-1.6	0.5	-1.1	-4.7	-3.5	-6.0	-4.1	-3.8								
2003	-0.3	1.2	2.5	-0.4	1.8	4.0	3.2	0.9	3.0	2.7	6.9	12.5	28.9							
2004	3.8	5.5	7.1	4.9	7.4	10.0	10.0	9.1	12.1	13.7	19.6	27.6	43.4	57.8						
2005	6.4	8.1	9.8	8.0	10.6	13.2	13.6	13.2	16.4	18.5	24.1	31.3	43.0	50.0	42.1					
2006	7.2	8.9	10.5	8.9	11.3	13.8	14.2	13.9	16.8	18.6	23.4	29.0	37.1	39.9	30.9	19.7				
2007	6.1	7.6	9.0	7.4	9.6	11.7	11.9	11.4	13.7	14.9	18.4	22.2	27.4	27.1	16.8	4.1	-11.4			
2008	1.9	3.0	4.0	2.2	3.9	5.4	5.0	3.9	5.2	5.4	7.3	9.0	11.1	7.5	-5.0	-20.8	-41.0	-70.6		
2009	3.8	5.0	6.1	4.5	6.2	7.8	7.6	6.9	8.3	8.8	10.8	12.7	15.1	12.8	3.8	-5.8	-14.3	-15.7	39.2	
2010	4.5	5.7	6.7	5.3	6.9	8.4	8.3	7.7	9.1	9.6	11.5	13.3	15.4	13.5	6.1	-1.1	-6.3	-4.6	28.4	17.6

Austria Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	6.3																				
1971	0.0	-6.3																			
1972	10.0	11.8	30.0																		
1973	8.0	8.5	15.9	1.9																	
1974	4.7	4.3	7.9	-3.2	-8.2																
1975	3.7	3.2	5.6	-2.6	-4.8	-1.4															
1976	3.2	2.7	4.5	-1.9	-3.2	-0.7	0.0														
1977	1.5	0.8	2.0	-3.6	-5.0	-3.9	-5.2	-10.5													
1978	0.9	0.3	1.2	-3.6	-4.7	-3.8	-4.6	-7.0	-3.4												
1979	1.6	1.1	2.0	-2.0	-2.6	-1.5	-1.5	-2.1	2.2	7.8											
1980	0.7	0.2	0.9	-2.8	-3.4	-2.6	-2.9	-3.6	-1.3	-0.3	-8.4										
1981	-0.5	-1.1	-0.6	-4.0	-4.7	-4.2	-4.7	-5.6	-4.4	-4.8	-11.0	-13.7									
1982	-1.5	-2.2	-1.8	-5.0	-5.8	-5.5	-6.0	-7.1	-6.4	-7.1	-12.0	-13.9	-14.1								
1983	-0.8	-1.3	-0.9	-3.7	-4.3	-3.9	-4.2	-4.8	-3.8	-3.9	-6.8	-6.3	-2.6	8.8							
1984	-0.5	-0.9	-0.5	-3.1	-3.5	-3.1	-3.3	-3.7	-2.7	-2.6	-4.6	-3.7	-0.4	6.5	4.1						
1985	8.6	8.7	9.8	8.2	8.8	10.3	11.5	12.7	15.6	18.4	20.1	25.8	35.7	52.3	74.1	144.1					
1986	8.3	8.4	9.4	7.9	8.4	9.8	10.8	11.9	14.4	16.6	17.8	22.2	29.4	40.2	50.7	74.0	4.0				
1987	6.4	6.4	7.2	5.7	5.9	7.0	7.7	8.4	10.3	11.8	12.3	15.3	20.1	27.0	31.5	40.6	-11.1	-26.2			
1988	6.6	6.6	7.3	5.9	6.2	7.2	7.9	8.5	10.2	11.6	12.0	14.6	18.6	24.1	27.2	32.9	-4.2	-8.2	9.8		
1989	10.9	11.2	12.2	11.1	11.7	13.0	14.0	15.1	17.2	19.1	20.3	23.4	28.1	34.1	38.3	45.1	20.4	25.9	51.9	94.1	
1990	9.8	9.9	10.8	9.7	10.2	11.3	12.2	13.0	14.8	16.4	17.2	19.7	23.4	28.1	30.9	35.3	13.6	16.0	30.0	40.1	-13.8
1991	8.5	8.6	9.4	8.3	8.6	9.6	10.3	11.0	12.5	13.8	14.3	16.3	19.3	23.0	24.8	27.8	8.4	9.2	18.1	20.9	-15.7
1992	7.6	7.7	8.4	7.3	7.6	8.4	9.0	9.6	10.9	11.9	12.2	14.0	16.5	19.5	20.7	22.8	5.5	5.7	12.1	12.7	-14.5
1993	8.5	8.6	9.3	8.3	8.6	9.5	10.1	10.7	12.0	13.1	13.4	15.1	17.5	20.4	21.6	23.5	8.4	9.0	14.9	16.0	-3.6
1994	7.2	7.3	7.9	6.9	7.1	7.9	8.4	8.8	9.9	10.8	11.0	12.4	14.4	16.7	17.5	18.8	4.9	5.0	9.4	9.4	-7.6
1995	6.3	6.3	6.8	5.8	6.0	6.7	7.1	7.4	8.4	9.1	9.2	10.4	12.1	14.1	14.6	15.5	2.7	2.5	6.1	5.6	-9.2
1996	6.4	6.4	7.0	6.0	6.2	6.8	7.2	7.6	8.5	9.2	9.3	10.4	12.0	13.8	14.2	15.1	3.4	3.3	6.6	6.2	-6.4
1997	6.7	6.7	7.2	6.3	6.5	7.1	7.5	7.9	8.8	9.4	9.5	10.6	12.1	13.8	14.2	14.9	4.2	4.2	7.2	7.0	-3.9
1998	6.1	6.1	6.6	5.7	5.8	6.4	6.8	7.1	7.9	8.5	8.5	9.4	10.8	12.4	12.6	13.2	3.1	3.1	5.7	5.3	-4.6
1999	6.0	6.0	6.4	5.6	5.7	6.3	6.6	6.9	7.6	8.2	8.2	9.1	10.3	11.8	12.0	12.5	3.1	3.0	5.4	5.0	-3.9
2000	5.5	5.5	5.9	5.0	5.2	5.7	5.9	6.2	6.9	7.4	7.4	8.2	9.3	10.6	10.7	11.1	2.3	2.1	4.3	3.9	-4.3
2001	5.2	5.2	5.6	4.7	4.8	5.3	5.6	5.8	6.5	6.9	6.9	7.6	8.6	9.8	9.9	10.2	1.9	1.7	3.7	3.3	-4.3
2002	4.9	4.9	5.2	4.4	4.5	5.0	5.2	5.4	6.0	6.4	6.4	7.0	8.0	9.1	9.1	9.4	1.5	1.3	3.2	2.7	-4.3
2003	5.8	5.8	6.2	5.4	5.5	6.0	6.3	6.5	7.2	7.6	7.6	8.3	9.3	10.4	10.4	10.8	3.4	3.3	5.2	4.9	-1.5
2004	7.4	7.5	7.9	7.2	7.4	7.9	8.2	8.5	9.2	9.7	9.8	10.5	11.6	12.7	12.9	13.4	6.5	6.6	8.5	8.5	2.8
2005	8.2	8.3	8.7	8.1	8.3	8.8	9.1	9.4	10.2	10.7	10.8	11.5	12.6	13.7	14.0	14.4	8.0	8.2	10.1	10.1	4.8
2006	8.6	8.7	9.1	8.5	8.7	9.2	9.6	9.9	10.6	11.1	11.2	11.9	13.0	14.1	14.3	14.8	8.6	8.9	10.7	10.8	5.9
2007	8.1	8.1	8.5	7.9	8.1	8.6	8.9	9.2	9.8	10.3	10.4	11.0	12.0	13.0	13.2	13.6	7.7	7.9	9.6	9.5	4.9
2008	6.1	6.1	6.4	5.8	5.9	6.3	6.5	6.7	7.3	7.7	7.7	8.2	9.0	9.9	10.0	10.2	4.4	4.4	5.9	5.7	1.0
2009	7.0	7.0	7.4	6.7	6.9	7.3	7.6	7.8	8.4	8.7	8.8	9.4	10.2	11.1	11.2	11.5	5.9	6.0	7.5	7.4	3.0
2010	7.2	7.2	7.6	7.0	7.1	7.6	7.8	8.0	8.6	9.0	9.0	9.6	10.4	11.3	11.4	11.7	6.4	6.5	7.9	7.8	3.7

Austria Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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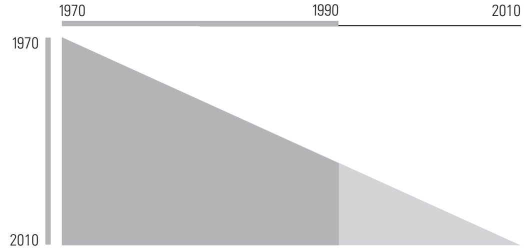
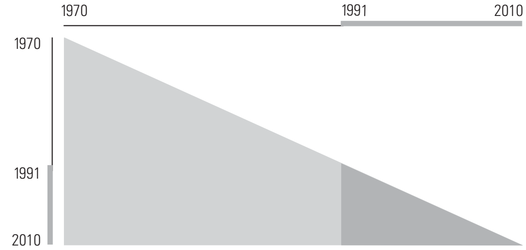
1990																				
1991	-17.6																			
1992	-14.8	-11.9																		
1993	-0.2	8.5	29.0																	
1994	-6.0	-2.1	2.8	-23.4																
1995	-8.2	-5.9	-3.8	-20.3	-17.1															
1996	-5.2	-2.7	-0.4	-10.1	-3.5	10.1														
1997	-2.5	0.0	2.4	-4.3	2.1	11.7	13.4													
1998	-3.4	-1.4	0.4	-5.3	-0.8	4.6	1.9	-9.6												
1999	-2.8	-0.9	0.7	-4.1	-0.2	4.1	2.0	-3.6	2.3											
2000	-3.4	-1.8	-0.5	-4.8	-1.7	1.4	-0.7	-5.4	-3.4	-9.1										
2001	-3.4	-2.0	-0.9	-4.7	-2.0	0.5	-1.4	-5.1	-3.5	-6.5	-3.9									
2002	-3.5	-2.2	-1.3	-4.6	-2.3	-0.2	-1.9	-4.9	-3.8	-5.8	-4.2	-4.5								
2003	-0.5	0.9	2.0	-0.7	1.9	4.2	3.4	1.8	4.0	4.4	8.9	15.4	35.2							
2004	3.9	5.6	7.1	5.1	7.9	10.7	10.8	10.4	13.7	16.0	22.3	31.0	48.7	62.2						
2005	6.1	7.8	9.3	7.6	10.5	13.2	13.6	13.6	16.9	19.3	25.0	32.2	44.5	49.1	36.1					
2006	7.1	8.7	10.2	8.8	11.5	14.1	14.4	14.6	17.6	19.8	24.6	30.3	38.9	40.2	29.2	22.4				
2007	5.9	7.4	8.7	7.3	9.6	11.9	12.0	11.9	14.3	15.7	19.3	23.2	28.7	27.1	15.3	5.0	-12.4			
2008	1.9	3.0	3.9	2.3	4.1	5.7	5.4	4.6	6.1	6.5	8.4	10.2	12.6	8.1	-5.4	-19.3	-40.1	-67.8		
2009	3.9	5.1	6.1	4.7	6.6	8.3	8.1	7.7	9.2	9.9	12.1	14.0	16.7	13.6	3.9	-4.2	-13.0	-13.3	41.2	
2010	4.6	5.7	6.7	5.4	7.2	8.8	8.7	8.4	9.9	10.5	12.5	14.3	16.7	14.0	6.0	0.0	-5.6	-3.3	28.9	16.6

Belgium Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-0.5																				
1971	0.8	2.2																			
1972	8.5	12.9	23.7																		
1973	6.2	8.5	11.6	-0.4																	
1974	-1.6	-1.9	-3.3	-16.8	-33.1																
1975	1.7	2.1	2.1	-5.1	-7.4	18.3															
1976	-0.2	-0.2	-0.6	-6.7	-8.8	3.4	-11.6														
1977	-1.3	-1.4	-2.0	-7.1	-8.8	-0.7	-10.2	-8.9													
1978	-0.5	-0.5	-0.9	-5.0	-5.9	1.0	-4.8	-1.5	5.9												
1979	0.3	0.3	0.1	-3.3	-3.7	2.2	-1.9	1.3	6.4	7.0											
1980	-1.8	-2.0	-2.4	-5.7	-6.4	-2.0	-6.0	-4.6	-3.2	-7.8	-22.6										
1981	-1.6	-1.7	-2.1	-5.0	-5.5	-1.6	-4.9	-3.6	-2.3	-5.0	-11.0	0.6									
1982	-0.6	-0.7	-0.9	-3.4	-3.7	0.0	-2.6	-1.2	0.4	-1.0	-3.6	5.8	11.1								
1983	1.9	2.1	2.1	0.2	0.2	3.9	2.1	4.1	6.2	6.3	6.1	15.7	23.3	35.4							
1984	2.8	3.0	3.1	1.4	1.5	5.0	3.5	5.4	7.4	7.7	7.8	15.4	20.4	25.0	14.7						
1985	4.6	4.9	5.1	3.7	4.0	7.4	6.3	8.2	10.4	11.0	11.7	18.6	23.1	27.1	22.9	31.1					
1986	6.5	6.9	7.2	6.1	6.6	9.9	9.1	11.2	13.4	14.3	15.4	21.7	25.9	29.7	27.7	34.3	37.5				
1987	5.0	5.4	5.6	4.3	4.7	7.6	6.7	8.4	10.1	10.5	11.0	15.8	18.3	19.8	15.9	16.3	8.9	-19.7			
1988	8.3	8.8	9.2	8.2	8.8	11.8	11.3	13.2	15.2	16.2	17.2	22.2	25.2	27.6	26.0	28.9	28.2	23.5	66.7		
1989	8.1	8.5	8.9	8.0	8.6	11.3	10.8	12.6	14.3	15.1	15.9	20.2	22.7	24.3	22.5	24.0	22.3	17.2	35.7	4.6	
1990	6.2	6.6	6.8	5.9	6.2	8.7	8.0	9.4	10.8	11.3	11.6	15.1	16.7	17.4	14.8	14.8	11.6	5.1	13.4	-13.3	-31.2
1991	6.3	6.6	6.8	5.9	6.3	8.6	8.0	9.3	10.6	10.9	11.3	14.3	15.7	16.2	13.8	13.7	10.8	5.5	11.8	-6.6	-12.1
1992	5.9	6.1	6.3	5.5	5.8	7.9	7.3	8.5	9.7	9.9	10.2	12.9	14.0	14.3	11.9	11.6	8.8	4.1	8.8	-5.7	-9.1
1993	6.8	7.1	7.3	6.5	6.9	9.0	8.5	9.7	10.8	11.1	11.4	14.1	15.2	15.6	13.6	13.5	11.3	7.5	12.1	1.1	0.2
1994	6.1	6.4	6.5	5.8	6.1	8.0	7.5	8.5	9.6	9.8	10.0	12.3	13.2	13.4	11.4	11.0	8.8	5.2	8.8	-0.9	-1.9
1995	6.2	6.5	6.7	5.9	6.2	8.1	7.6	8.6	9.6	9.8	10.0	12.1	13.0	13.1	11.2	10.9	8.9	5.7	8.9	0.7	0.0
1996	6.6	6.8	7.0	6.3	6.6	8.4	8.0	8.9	9.9	10.1	10.3	12.3	13.1	13.3	11.6	11.3	9.5	6.7	9.7	2.5	2.2
1997	7.3	7.6	7.8	7.2	7.5	9.3	8.9	9.8	10.8	11.0	11.3	13.2	14.0	14.2	12.7	12.6	11.0	8.6	11.5	5.3	5.4
1998	8.8	9.2	9.4	8.9	9.3	11.0	10.7	11.7	12.7	13.0	13.4	15.4	16.2	16.6	15.3	15.3	14.1	12.2	15.1	9.9	10.5
1999	8.4	8.7	9.0	8.4	8.8	10.5	10.1	11.1	12.0	12.3	12.5	14.4	15.1	15.4	14.1	14.1	12.9	11.0	13.5	8.7	9.1
2000	7.6	7.9	8.1	7.6	7.9	9.4	9.1	9.9	10.8	11.0	11.2	12.9	13.5	13.6	12.3	12.2	10.9	9.1	11.3	6.6	6.8
2001	7.1	7.3	7.5	6.9	7.2	8.7	8.3	9.1	9.9	10.0	10.2	11.7	12.3	12.4	11.1	10.9	9.6	7.7	9.7	5.3	5.4
2002	5.9	6.1	6.2	5.6	5.8	7.2	6.8	7.5	8.2	8.3	8.3	9.7	10.2	10.1	8.8	8.5	7.1	5.3	6.9	2.6	2.5
2003	6.0	6.2	6.3	5.8	6.0	7.3	6.9	7.6	8.2	8.3	8.4	9.7	10.2	10.1	8.8	8.5	7.3	5.5	7.1	3.1	3.0
2004	6.7	6.9	7.0	6.5	6.7	8.1	7.7	8.4	9.1	9.2	9.3	10.6	11.0	11.0	9.9	9.6	8.5	6.9	8.4	4.8	4.8
2005	7.2	7.4	7.5	7.0	7.3	8.6	8.2	8.9	9.6	9.7	9.8	11.1	11.5	11.6	10.5	10.3	9.2	7.8	9.3	5.9	6.0
2006	7.5	7.7	7.9	7.4	7.6	8.9	8.6	9.3	9.9	10.1	10.2	11.4	11.9	11.9	10.9	10.7	9.7	8.3	9.8	6.7	6.8
2007	6.9	7.1	7.2	6.7	7.0	8.2	7.9	8.5	9.1	9.2	9.2	10.4	10.8	10.8	9.8	9.6	8.6	7.2	8.6	5.5	5.5
2008	4.9	5.1	5.2	4.6	4.8	5.9	5.5	6.1	6.5	6.6	6.6	7.6	7.9	7.7	6.6	6.3	5.2	3.7	4.9	1.8	1.6
2009	6.1	6.2	6.3	5.9	6.0	7.2	6.8	7.4	7.9	8.0	8.0	9.1	9.4	9.3	8.3	8.0	7.1	5.7	6.9	4.1	4.0
2010	6.0	6.2	6.3	5.8	6.0	7.1	6.7	7.3	7.8	7.8	7.9	8.9	9.2	9.1	8.1	7.9	6.9	5.7	6.8	4.0	4.0

Belgium Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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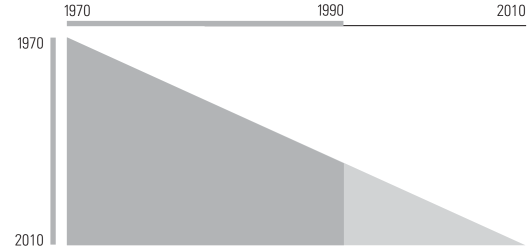
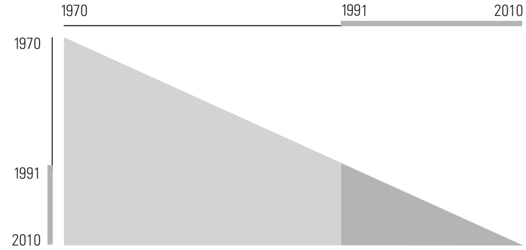
1990																				
1991	6.9																			
1992	2.0	-3.0																		
1993	10.7	12.6	28.3																	
1994	5.4	4.8	8.8	-10.7																
1995	6.2	6.1	9.1	-0.5	9.8															
1996	7.8	8.0	10.7	4.8	12.6	15.5														
1997	10.6	11.2	14.1	10.6	17.6	21.6	27.7													
1998	15.7	17.0	20.3	18.7	26.1	31.5	39.5	51.4												
1999	13.6	14.4	16.9	15.0	20.2	22.8	25.2	24.0	-3.4											
2000	10.6	11.0	12.8	10.6	14.1	15.0	14.9	10.6	-9.7	-16.1										
2001	8.7	8.9	10.2	8.0	10.6	10.8	9.8	5.3	-10.0	-13.3	-10.5									
2002	5.3	5.2	6.0	3.5	5.3	4.6	2.8	-2.2	-15.5	-19.6	-21.4	-32.2								
2003	5.6	5.5	6.3	4.1	5.7	5.2	3.8	-0.2	-10.5	-12.3	-11.0	-11.3	9.6							
2004	7.4	7.4	8.3	6.5	8.2	8.0	7.1	4.1	-3.7	-3.8	-0.7	2.5	19.9	30.2						
2005	8.5	8.6	9.5	7.9	9.6	9.6	8.9	6.6	0.2	0.7	4.1	7.8	21.1	26.8	23.5					
2006	9.2	9.3	10.2	8.8	10.4	10.5	10.0	8.0	2.6	3.4	6.7	10.1	20.7	24.4	21.6	19.6				
2007	7.7	7.7	8.5	7.0	8.4	8.3	7.6	5.6	0.6	1.1	3.5	5.8	13.5	14.4	9.2	2.0	-15.6			
2008	3.4	3.2	3.6	2.0	2.9	2.4	1.3	-1.1	-6.4	-6.7	-5.5	-4.8	-0.3	-2.2	-10.3	-21.6	-42.2	-68.8		
2009	5.9	5.8	6.3	5.0	6.0	5.8	5.0	3.1	-1.3	-1.1	0.6	2.0	6.9	6.4	1.7	-3.8	-11.6	-9.5	49.7	
2010	5.8	5.7	6.2	4.9	5.9	5.6	4.9	3.2	-0.9	-0.6	0.9	2.2	6.5	6.0	2.0	-2.3	-7.8	-5.1	26.7	3.7

Belgium Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-0.5																				
1971	6.8	14.0																			
1972	12.8	19.5	24.9																		
1973	11.3	15.3	15.9	6.9																	
1974	4.4	5.6	2.8	-8.3	-23.5																
1975	4.6	5.7	3.6	-3.5	-8.8	5.9															
1976	4.0	4.7	2.9	-2.6	-5.8	3.0	0.1														
1977	3.3	3.8	2.1	-2.4	-4.7	1.5	-0.7	-1.5													
1978	5.1	5.8	4.6	1.2	0.1	5.9	6.0	8.9	19.3												
1979	5.3	6.0	5.0	2.1	1.4	6.3	6.4	8.5	13.5	7.8											
1980	2.2	2.5	1.2	-1.7	-3.0	0.4	-0.6	-0.8	-0.6	-10.5	-28.9										
1981	-0.1	0.0	-1.4	-4.4	-5.8	-3.2	-4.8	-5.8	-6.8	-15.5	-27.2	-25.4									
1982	-0.2	-0.2	-1.5	-4.1	-5.3	-3.0	-4.3	-5.1	-5.8	-12.0	-18.6	-13.5	-1.6								
1983	0.9	1.0	-0.1	-2.3	-3.3	-1.0	-1.9	-2.2	-2.3	-6.6	-10.2	-3.9	6.8	15.2							
1984	1.0	1.1	0.1	-1.9	-2.7	-0.7	-1.4	-1.6	-1.6	-5.1	-7.6	-2.3	5.4	8.9	2.6						
1985	5.0	5.4	4.8	3.2	2.9	5.3	5.3	5.8	6.8	5.0	4.5	11.2	20.3	27.6	33.9	65.2					
1986	8.8	9.4	9.1	7.9	8.0	10.6	11.0	12.1	13.7	13.0	13.7	20.8	30.0	37.9	45.5	67.0	68.9				
1987	8.2	8.7	8.4	7.3	7.3	9.7	10.0	10.9	12.1	11.3	11.8	17.6	24.8	30.0	33.7	44.1	33.6	-1.7			
1988	10.3	10.9	10.8	9.9	10.1	12.5	13.0	14.0	15.4	15.1	15.9	21.5	28.2	33.1	36.7	45.3	38.6	23.5	48.6		
1989	10.3	10.9	10.7	9.9	10.0	12.3	12.7	13.7	15.0	14.6	15.3	20.2	25.9	29.8	32.2	38.2	31.4	18.9	29.2	9.8	
1990	8.8	9.3	9.0	8.2	8.2	10.2	10.5	11.2	12.2	11.6	12.0	16.1	20.7	23.5	24.6	28.3	20.9	9.0	12.5	-5.6	-20.9
1991	8.7	9.1	8.9	8.0	8.1	9.9	10.2	10.9	11.8	11.2	11.5	15.1	19.2	21.5	22.3	25.1	18.4	8.3	10.8	-1.8	-7.6
1992	7.9	8.3	8.0	7.2	7.2	8.9	9.1	9.7	10.4	9.8	9.9	13.1	16.7	18.5	18.8	20.9	14.6	5.5	6.9	-3.5	-7.9
1993	8.3	8.7	8.5	7.7	7.7	9.4	9.6	10.1	10.9	10.3	10.5	13.5	16.8	18.4	18.7	20.5	15.0	7.3	8.8	0.8	-1.5
1994	8.1	8.4	8.2	7.4	7.4	9.0	9.1	9.6	10.3	9.7	9.9	12.6	15.6	17.0	17.2	18.6	13.5	6.5	7.7	0.9	-0.9
1995	8.5	8.8	8.6	7.9	8.0	9.4	9.6	10.1	10.8	10.3	10.4	13.1	15.8	17.1	17.3	18.6	14.0	7.9	9.1	3.4	2.4
1996	8.4	8.8	8.6	7.9	7.9	9.3	9.5	10.0	10.6	10.1	10.2	12.7	15.2	16.4	16.5	17.7	13.4	7.8	8.8	3.9	3.0
1997	8.5	8.8	8.6	7.9	8.0	9.3	9.5	9.9	10.5	10.1	10.2	12.5	14.9	16.0	16.0	17.0	13.0	8.0	8.9	4.5	3.8
1998	10.3	10.7	10.6	10.1	10.2	11.6	11.8	12.4	13.0	12.7	13.0	15.3	17.7	18.9	19.2	20.3	16.9	12.6	13.8	10.4	10.4
1999	9.4	9.8	9.6	9.0	9.1	10.4	10.6	11.1	11.6	11.3	11.4	13.6	15.7	16.8	16.9	17.8	14.4	10.2	11.2	7.8	7.6
2000	8.4	8.7	8.5	8.0	8.0	9.2	9.3	9.7	10.2	9.8	9.9	11.8	13.8	14.6	14.6	15.4	12.0	8.0	8.7	5.4	5.0
2001	7.7	8.0	7.7	7.2	7.2	8.3	8.4	8.7	9.1	8.7	8.7	10.5	12.3	13.1	13.0	13.6	10.3	6.4	7.0	3.8	3.3
2002	6.8	7.1	6.8	6.2	6.2	7.3	7.3	7.6	8.0	7.5	7.5	9.1	10.8	11.4	11.2	11.7	8.6	4.8	5.2	2.1	1.5
2003	7.6	7.8	7.6	7.1	7.1	8.1	8.2	8.5	8.9	8.5	8.5	10.1	11.7	12.4	12.2	12.8	9.8	6.4	6.9	4.1	3.7
2004	8.5	8.8	8.6	8.1	8.1	9.2	9.3	9.6	10.1	9.7	9.8	11.4	13.0	13.7	13.6	14.1	11.4	8.3	8.8	6.3	6.1
2005	8.5	8.7	8.6	8.1	8.1	9.1	9.2	9.6	10.0	9.6	9.7	11.2	12.7	13.4	13.3	13.8	11.2	8.2	8.7	6.4	6.2
2006	9.2	9.4	9.3	8.8	8.9	9.9	10.0	10.4	10.8	10.5	10.6	12.1	13.6	14.2	14.2	14.7	12.3	9.5	10.1	7.9	7.8
2007	8.7	9.0	8.9	8.4	8.4	9.4	9.5	9.8	10.2	9.9	10.0	11.4	12.8	13.4	13.3	13.8	11.4	8.7	9.2	7.2	7.0
2008	6.7	6.9	6.7	6.2	6.2	7.1	7.1	7.3	7.6	7.2	7.2	8.5	9.7	10.2	10.0	10.3	7.9	5.1	5.4	3.3	2.9
2009	7.9	8.1	8.0	7.5	7.5	8.4	8.5	8.7	9.1	8.7	8.8	10.1	11.3	11.8	11.7	12.0	9.8	7.3	7.7	5.7	5.5
2010	7.6	7.8	7.7	7.2	7.2	8.1	8.2	8.4	8.7	8.4	8.4	9.6	10.8	11.3	11.1	11.5	9.3	6.8	7.2	5.3	5.1

Belgium Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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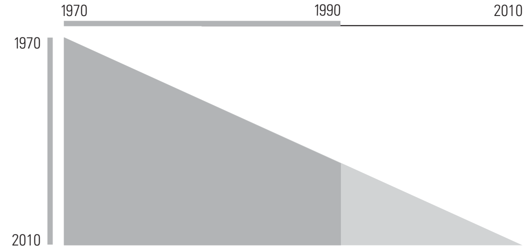
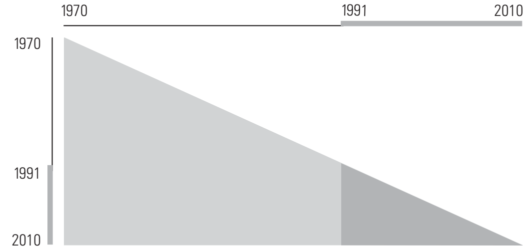
1990																				
1991	5.7																			
1992	-1.4	-8.6																		
1993	5.0	4.6	17.9																	
1994	4.1	3.6	9.6	1.4																
1995	7.0	7.4	12.7	10.1	18.7															
1996	7.0	7.3	11.2	9.0	12.9	7.0														
1997	7.4	7.6	10.9	9.2	11.7	8.2	9.5													
1998	14.3	15.6	19.6	20.0	24.6	26.6	36.3	63.2												
1999	10.8	11.4	14.3	13.7	16.2	15.5	18.4	22.8	-17.6											
2000	7.6	7.8	9.8	8.7	9.9	8.1	8.4	8.1	-19.5	-21.4										
2001	5.5	5.5	7.1	5.7	6.3	4.3	3.7	2.3	-18.0	-18.2	-15.1									
2002	3.4	3.2	4.4	2.8	3.0	0.8	-0.2	-2.2	-18.5	-18.9	-17.6	-20.1								
2003	5.6	5.6	6.8	5.7	6.2	4.7	4.3	3.5	-8.5	-6.2	-1.1	5.8	31.8							
2004	8.0	8.2	9.6	8.9	9.6	8.6	8.8	8.7	-0.4	3.1	9.2	17.3	36.0	40.3						
2005	8.0	8.2	9.4	8.7	9.4	8.5	8.6	8.5	0.7	3.8	8.8	14.8	26.4	23.7	7.1					
2006	9.6	9.9	11.2	10.7	11.4	10.8	11.1	11.3	4.8	8.0	13.0	18.6	28.2	27.0	20.4	33.7				
2007	8.7	8.8	10.0	9.4	10.1	9.3	9.5	9.6	3.6	6.2	10.2	14.4	21.3	18.7	11.5	13.7	-6.4			
2008	4.3	4.2	5.0	4.1	4.3	3.2	2.9	2.3	-3.8	-2.3	0.1	2.3	6.0	0.9	-9.0	-14.4	-38.4	-70.4		
2009	6.9	7.0	7.9	7.3	7.7	6.9	6.9	6.6	1.5	3.4	6.2	8.8	13.0	9.8	3.7	2.9	-7.4	-7.9	54.6	
2010	6.4	6.5	7.3	6.7	7.0	6.2	6.2	5.9	1.1	2.8	5.2	7.5	11.0	8.0	2.6	1.7	-6.3	-6.3	25.8	-3.1

Belgium Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	0.7																				
1971	3.2	5.7																			
1972	11.5	16.9	28.1																		
1973	9.2	12.0	15.1	2.1																	
1974	0.4	0.3	-1.5	-16.3	-34.6																
1975	4.0	4.6	4.4	-3.6	-6.4	21.8															
1976	1.8	2.0	1.2	-5.5	-8.1	5.2	-11.3														
1977	0.9	0.9	0.1	-5.5	-7.4	1.6	-8.4	-5.5													
1978	1.7	1.9	1.3	-3.1	-4.2	3.4	-2.7	1.6	8.8												
1979	2.4	2.5	2.1	-1.6	-2.2	4.3	-0.1	3.7	8.3	7.8											
1980	0.0	-0.1	-0.7	-4.3	-5.2	-0.3	-4.7	-3.1	-2.3	-7.8	-23.5										
1981	0.1	0.1	-0.5	-3.7	-4.4	-0.1	-3.8	-2.2	-1.4	-4.8	-11.1	1.2									
1982	1.0	1.1	0.7	-2.1	-2.6	1.4	-1.5	0.2	1.3	-0.5	-3.3	6.8	12.3								
1983	3.8	4.0	3.9	1.6	1.6	5.6	3.6	5.7	7.6	7.4	7.3	17.5	25.7	39.0							
1984	4.6	4.9	4.9	2.9	3.0	6.8	5.1	7.2	9.0	9.0	9.2	17.4	22.8	28.0	17.0						
1985	6.5	6.9	6.9	5.3	5.6	9.2	8.0	10.1	12.1	12.5	13.3	20.7	25.5	29.9	25.4	33.8					
1986	8.4	8.9	9.1	7.8	8.2	11.8	10.9	13.1	15.2	15.9	17.1	23.9	28.4	32.4	30.2	36.8	39.8				
1987	7.0	7.4	7.5	6.1	6.4	9.5	8.5	10.3	11.9	12.2	12.8	18.0	20.8	22.5	18.3	18.8	11.3	-17.3			
1988	10.3	10.8	11.1	10.1	10.6	13.8	13.2	15.3	17.2	18.0	19.1	24.4	27.8	30.3	28.6	31.5	30.7	26.2	69.7		
1989	10.1	10.6	10.8	9.8	10.3	13.3	12.7	14.5	16.2	16.9	17.8	22.4	25.0	26.8	24.8	26.4	24.5	19.4	37.8	5.8	
1990	8.2	8.5	8.7	7.6	7.9	10.6	9.8	11.3	12.6	13.0	13.4	17.1	18.9	19.7	16.9	16.9	13.6	7.0	15.1	-12.2	-30.2
1991	8.1	8.5	8.6	7.6	7.9	10.4	9.6	11.0	12.2	12.5	12.9	16.2	17.7	18.3	15.7	15.5	12.4	7.0	13.0	-5.8	-11.7
1992	7.6	7.9	8.0	7.0	7.2	9.6	8.8	10.1	11.1	11.3	11.6	14.5	15.7	16.1	13.5	13.1	10.1	5.1	9.6	-5.4	-9.1
1993	8.4	8.7	8.9	7.9	8.2	10.5	9.9	11.1	12.1	12.4	12.7	15.5	16.7	17.1	14.9	14.6	12.2	8.3	12.6	1.1	0.0
1994	7.7	8.0	8.1	7.1	7.4	9.5	8.8	10.0	10.9	11.0	11.2	13.7	14.6	14.8	12.6	12.2	9.8	6.0	9.4	-0.7	-2.0
1995	7.9	8.1	8.2	7.4	7.6	9.6	9.0	10.1	11.0	11.1	11.3	13.6	14.5	14.7	12.6	12.2	10.1	6.8	9.8	1.2	0.5
1996	8.3	8.6	8.7	7.9	8.1	10.0	9.5	10.5	11.4	11.5	11.7	13.9	14.8	15.0	13.1	12.8	10.9	8.0	10.8	3.4	3.1
1997	9.0	9.3	9.5	8.7	9.0	10.9	10.4	11.5	12.3	12.5	12.7	14.9	15.7	16.0	14.3	14.1	12.5	10.0	12.7	6.4	6.4
1998	10.5	10.9	11.1	10.4	10.8	12.7	12.3	13.3	14.2	14.5	14.9	17.0	17.9	18.3	16.9	16.9	15.6	13.5	16.4	11.0	11.6
1999	10.1	10.5	10.6	10.0	10.3	12.1	11.7	12.7	13.5	13.7	14.0	16.0	16.8	17.1	15.7	15.6	14.3	12.4	14.8	9.8	10.2
2000	9.3	9.6	9.7	9.1	9.3	11.0	10.6	11.5	12.3	12.4	12.6	14.4	15.1	15.3	13.9	13.7	12.4	10.4	12.5	7.8	7.9
2001	8.7	9.0	9.1	8.4	8.7	10.3	9.8	10.7	11.3	11.5	11.6	13.3	13.9	14.0	12.6	12.3	11.0	9.1	10.9	6.4	6.5
2002	7.5	7.7	7.8	7.1	7.3	8.8	8.3	9.1	9.7	9.7	9.8	11.3	11.8	11.7	10.3	9.9	8.5	6.6	8.2	3.8	3.6
2003	7.6	7.9	7.9	7.3	7.4	8.9	8.4	9.2	9.7	9.8	9.9	11.3	11.8	11.7	10.4	10.0	8.7	6.9	8.4	4.3	4.2
2004	8.4	8.6	8.7	8.1	8.3	9.7	9.3	10.0	10.6	10.6	10.8	12.2	12.7	12.7	11.4	11.1	9.9	8.3	9.8	6.0	6.1
2005	8.8	9.0	9.1	8.6	8.8	10.2	9.8	10.5	11.1	11.2	11.3	12.7	13.2	13.2	12.0	11.8	10.7	9.2	10.6	7.2	7.2
2006	9.1	9.4	9.5	8.9	9.1	10.5	10.1	10.8	11.4	11.5	11.6	13.0	13.5	13.5	12.4	12.2	11.2	9.7	11.1	7.9	8.0
2007	8.5	8.7	8.8	8.2	8.4	9.7	9.3	10.0	10.5	10.6	10.7	11.9	12.3	12.3	11.2	11.0	9.9	8.5	9.8	6.7	6.7
2008	6.5	6.7	6.7	6.1	6.2	7.4	7.0	7.5	8.0	7.9	7.9	9.1	9.3	9.2	8.0	7.7	6.5	5.0	6.1	2.9	2.7
2009	7.7	7.8	7.9	7.3	7.5	8.7	8.3	8.9	9.4	9.4	9.4	10.6	10.9	10.8	9.8	9.5	8.4	7.1	8.2	5.3	5.2
2010	7.6	7.8	7.9	7.3	7.5	8.6	8.2	8.8	9.3	9.3	9.3	10.4	10.7	10.7	9.6	9.3	8.4	7.1	8.1	5.3	5.3

Belgium Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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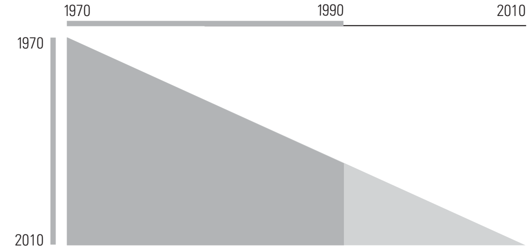
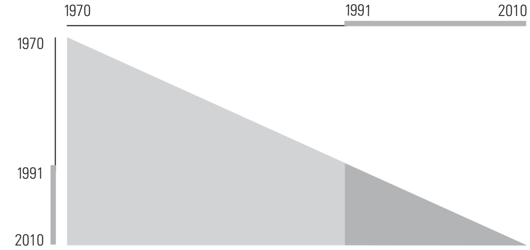
1991	6.9																			
1992	1.4	-4.0																		
1993	10.0	11.6	27.2																	
1994	5.1	4.5	8.7	-9.7																
1995	6.6	6.5	10.0	1.5	12.7															
1996	8.6	9.0	12.2	7.2	15.7	18.8														
1997	11.7	12.5	15.8	12.9	20.5	24.4	30.0													
1998	16.8	18.2	21.9	20.9	28.6	33.9	41.4	52.8												
1999	14.7	15.7	18.5	17.1	22.5	24.9	27.0	25.4	-2.0											
2000	11.8	12.3	14.3	12.5	16.2	16.9	16.5	11.9	-8.5	-15.0										
2001	9.8	10.1	11.7	9.7	12.5	12.5	11.2	6.5	-8.9	-12.4	-9.8									
2002	6.4	6.4	7.4	5.2	7.1	6.3	4.3	-0.9	-14.3	-18.4	-20.2	-30.6								
2003	6.8	6.8	7.8	5.9	7.6	7.0	5.3	1.2	-9.1	-10.9	-9.6	-9.5	11.5							
2004	8.7	8.8	9.9	8.3	10.1	9.8	8.7	5.6	-2.2	-2.3	0.9	4.4	22.0	32.4						
2005	9.7	9.9	11.0	9.7	11.4	11.3	10.5	8.0	1.6	2.2	5.7	9.5	22.9	28.6	24.9					
2006	10.4	10.6	11.7	10.5	12.2	12.1	11.5	9.4	4.0	4.8	8.1	11.7	22.3	25.9	22.6	20.3				
2007	8.9	9.0	9.9	8.6	10.0	9.8	9.0	6.9	1.8	2.3	4.7	7.2	14.7	15.5	9.9	2.4	-15.5			
2008	4.6	4.4	5.0	3.5	4.4	3.8	2.6	0.1	-5.2	-5.6	-4.4	-3.6	0.9	-1.3	-9.7	-21.2	-42.0	-68.4		
2009	7.1	7.1	7.8	6.6	7.6	7.3	6.4	4.4	0.0	0.2	1.9	3.4	8.2	7.7	2.8	-2.8	-10.5	-7.9	52.5	
2010	7.1	7.1	7.7	6.5	7.6	7.2	6.4	4.6	0.6	0.8	2.4	3.7	8.0	7.5	3.4	-0.9	-6.3	-3.2	29.4	6.4

Belgium Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	0.7																				
1971	3.8	7.0																			
1972	11.8	17.4	27.9																		
1973	9.6	12.6	15.5	3.0																	
1974	-0.2	-0.4	-2.9	-18.3	-39.6																
1975	2.8	3.2	2.2	-6.3	-11.0	17.7															
1976	1.0	1.1	-0.1	-7.1	-10.5	4.1	-9.5														
1977	0.0	-0.1	-1.3	-7.1	-9.6	0.4	-8.3	-7.1													
1978	0.9	0.9	0.1	-4.6	-6.1	2.3	-2.8	0.5	8.2												
1979	1.4	1.5	0.8	-3.0	-4.1	3.1	-0.6	2.4	7.1	6.1											
1980	-0.4	-0.5	-1.3	-5.0	-6.1	-0.6	-4.2	-2.9	-1.5	-6.3	-18.7										
1981	-0.9	-1.1	-1.9	-5.2	-6.2	-1.5	-4.7	-3.7	-2.8	-6.5	-12.8	-6.9									
1982	0.5	0.5	-0.1	-2.9	-3.6	0.9	-1.5	-0.2	1.2	-0.5	-2.7	5.3	17.4								
1983	2.9	3.0	2.7	0.4	0.1	4.6	2.9	4.7	6.7	6.4	6.4	14.8	25.7	33.9							
1984	3.8	4.0	3.8	1.7	1.6	5.8	4.4	6.2	8.1	8.0	8.4	15.2	22.6	25.2	16.5						
1985	6.2	6.6	6.6	4.9	5.1	9.2	8.3	10.3	12.5	13.1	14.3	20.8	27.8	31.2	29.9	43.3					
1986	8.6	9.1	9.3	8.0	8.3	12.3	11.8	14.0	16.3	17.3	19.0	25.2	31.7	35.2	35.7	45.3	47.2				
1987	6.5	6.9	6.9	5.5	5.6	9.1	8.4	10.0	11.8	12.2	12.9	17.4	21.5	22.3	19.4	20.4	8.9	-29.4			
1988	9.8	10.3	10.5	9.4	9.8	13.4	13.0	14.9	16.9	17.8	19.1	23.8	28.2	30.0	29.2	32.4	28.7	19.5	68.4		
1989	9.6	10.1	10.2	9.2	9.6	12.9	12.5	14.2	16.0	16.7	17.8	21.8	25.4	26.6	25.3	27.1	23.1	15.0	37.3	6.1	
1990	7.5	7.8	7.9	6.8	7.0	9.9	9.4	10.7	12.1	12.4	13.0	16.2	18.7	18.9	16.7	16.8	11.5	2.5	13.2	-14.4	-34.9
1991	7.5	7.8	7.8	6.8	7.0	9.7	9.2	10.5	11.7	12.0	12.5	15.3	17.5	17.5	15.5	15.4	10.7	3.4	11.6	-7.3	-14.0
1992	7.0	7.3	7.3	6.2	6.4	9.0	8.5	9.6	10.7	10.9	11.2	13.7	15.6	15.4	13.4	13.0	8.7	2.2	8.6	-6.4	-10.5
1993	7.7	8.0	8.1	7.1	7.3	9.8	9.4	10.5	11.6	11.8	12.2	14.6	16.4	16.3	14.5	14.3	10.7	5.5	11.3	-0.1	-1.7
1994	7.0	7.2	7.2	6.3	6.5	8.8	8.3	9.3	10.3	10.4	10.7	12.8	14.3	14.0	12.2	11.8	8.3	3.4	8.1	-1.9	-3.6
1995	7.2	7.5	7.5	6.6	6.8	9.0	8.6	9.5	10.4	10.6	10.9	12.8	14.2	14.0	12.3	12.0	8.8	4.6	8.8	0.3	-0.7
1996	7.6	7.9	7.9	7.1	7.2	9.4	9.0	9.9	10.8	10.9	11.2	13.1	14.4	14.2	12.7	12.4	9.6	5.8	9.7	2.4	1.9
1997	8.3	8.5	8.6	7.8	8.0	10.1	9.8	10.7	11.6	11.7	12.1	13.9	15.2	15.0	13.7	13.4	10.9	7.7	11.4	5.0	4.9
1998	10.0	10.3	10.4	9.7	10.0	12.1	11.8	12.8	13.7	14.0	14.4	16.3	17.6	17.7	16.6	16.6	14.5	11.8	15.6	10.3	10.7
1999	9.5	9.8	9.9	9.3	9.5	11.5	11.2	12.1	13.0	13.2	13.6	15.3	16.5	16.5	15.4	15.3	13.3	10.7	14.0	9.1	9.4
2000	8.8	9.0	9.1	8.4	8.6	10.5	10.2	11.0	11.8	12.0	12.3	13.8	14.9	14.8	13.7	13.5	11.5	8.9	11.9	7.2	7.3
2001	8.2	8.5	8.5	7.8	8.0	9.8	9.5	10.2	11.0	11.1	11.3	12.7	13.7	13.5	12.4	12.2	10.2	7.7	10.4	5.9	5.9
2002	6.9	7.1	7.1	6.4	6.5	8.1	7.8	8.5	9.1	9.1	9.3	10.5	11.4	11.0	9.8	9.5	7.5	5.0	7.3	2.9	2.7
2003	7.1	7.3	7.3	6.6	6.8	8.4	8.0	8.7	9.3	9.3	9.5	10.7	11.5	11.2	10.1	9.7	7.9	5.6	7.7	3.7	3.5
2004	7.9	8.1	8.1	7.5	7.7	9.2	8.9	9.6	10.2	10.3	10.5	11.7	12.5	12.3	11.2	11.0	9.3	7.2	9.3	5.6	5.6
2005	8.3	8.5	8.5	7.9	8.1	9.6	9.4	10.0	10.6	10.7	10.9	12.1	12.9	12.7	11.7	11.5	9.9	7.9	10.0	6.5	6.6
2006	8.7	8.9	8.9	8.4	8.5	10.0	9.8	10.4	11.0	11.1	11.3	12.5	13.3	13.1	12.2	12.0	10.5	8.7	10.7	7.5	7.5
2007	8.0	8.2	8.2	7.7	7.8	9.2	9.0	9.6	10.1	10.2	10.3	11.4	12.1	11.9	11.0	10.7	9.3	7.4	9.3	6.2	6.2
2008	6.1	6.2	6.2	5.6	5.7	7.0	6.7	7.2	7.7	7.6	7.7	8.6	9.2	8.9	7.9	7.5	6.0	4.1	5.7	2.6	2.4
2009	7.3	7.5	7.5	6.9	7.1	8.4	8.1	8.7	9.1	9.2	9.3	10.2	10.9	10.6	9.7	9.4	8.0	6.3	8.0	5.1	5.0
2010	7.3	7.4	7.5	6.9	7.0	8.3	8.1	8.6	9.1	9.1	9.2	10.1	10.7	10.4	9.6	9.3	8.0	6.3	7.9	5.1	5.1

Belgium Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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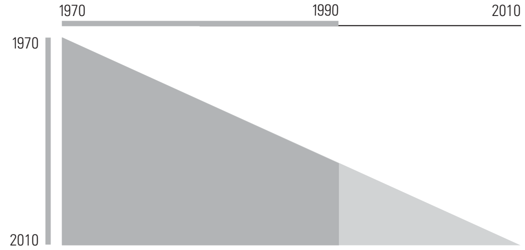
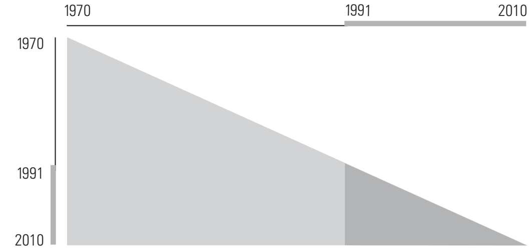
1991	6.9																			
1992	1.6	-3.6																		
1993	9.4	10.6	24.9																	
1994	4.3	3.4	6.9	-11.0																
1995	6.2	6.0	9.2	1.3	13.6															
1996	8.0	8.2	11.2	6.6	15.5	17.3														
1997	10.6	11.2	14.1	11.5	18.9	21.6	25.9													
1998	16.4	17.8	21.4	20.7	28.6	33.6	41.7	57.5												
1999	14.3	15.2	17.9	16.8	22.3	24.5	26.9	27.4	-2.6											
2000	11.5	12.0	14.0	12.4	16.3	16.8	16.7	13.6	-8.3	-13.9										
2001	9.6	9.9	11.4	9.7	12.7	12.5	11.6	8.0	-8.5	-11.5	-9.0									
2002	5.8	5.7	6.7	4.6	6.6	5.6	3.6	-0.8	-15.4	-19.6	-22.5	-36.0								
2003	6.5	6.4	7.4	5.6	7.5	6.7	5.2	1.7	-9.4	-11.2	-10.2	-10.8	14.3							
2004	8.5	8.6	9.6	8.3	10.2	9.8	8.9	6.4	-2.1	-2.0	1.0	4.4	24.5	34.8						
2005	9.3	9.5	10.5	9.3	11.2	10.9	10.2	8.3	1.2	1.9	5.0	8.5	23.4	27.9	21.1					
2006	10.2	10.4	11.4	10.4	12.2	12.0	11.5	9.9	4.0	4.9	8.0	11.4	23.3	26.3	22.1	23.0				
2007	8.6	8.7	9.5	8.4	9.9	9.6	8.9	7.2	1.6	2.2	4.5	6.7	15.2	15.5	9.1	3.1	-16.9			
2008	4.5	4.3	4.8	3.5	4.5	3.8	2.7	0.6	-5.1	-5.4	-4.3	-3.6	1.8	-0.7	-9.6	-19.9	-41.3	-65.7		
2009	7.1	7.1	7.8	6.7	7.9	7.5	6.7	5.1	0.4	0.7	2.3	3.7	9.4	8.5	3.3	-1.2	-9.2	-5.4	54.9	
2010	7.1	7.1	7.7	6.7	7.8	7.4	6.7	5.2	0.8	1.2	2.7	4.0	8.9	8.2	3.8	0.3	-5.4	-1.6	30.5	6.1

Canada Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	0.1																				
1971	3.0	6.0																			
1972	10.6	15.8	25.6																		
1973	5.4	7.2	7.9	-9.9																	
1974	-2.7	-3.5	-6.6	-22.7	-35.5																
1975	-0.7	-0.9	-2.6	-12.0	-13.0	9.4															
1976	-0.6	-0.8	-2.1	-9.1	-8.8	4.6	-0.2														
1977	-0.9	-1.0	-2.2	-7.7	-7.2	2.3	-1.3	-2.3													
1978	1.7	1.8	1.3	-2.8	-1.4	7.1	6.4	9.7	21.7												
1979	5.6	6.2	6.2	3.4	5.6	13.9	15.0	20.1	31.3	40.8											
1980	6.2	6.8	6.9	4.5	6.6	13.6	14.5	18.2	25.0	26.6	12.4										
1981	3.7	4.0	3.8	1.4	2.8	8.3	8.1	9.8	12.8	9.8	-5.7	-23.8									
1982	2.7	3.0	2.7	0.4	1.5	6.2	5.7	6.7	8.5	5.2	-6.7	-16.3	-8.7								
1983	4.1	4.4	4.3	2.4	3.6	7.9	7.8	8.9	10.8	8.6	0.5	-3.5	6.7	22.1							
1984	2.9	3.1	2.9	1.0	2.0	5.8	5.4	6.1	7.3	4.9	-2.3	-6.0	0.0	4.3	-13.6						
1985	3.5	3.7	3.5	1.8	2.8	6.3	6.0	6.7	7.8	5.8	0.0	-2.5	2.8	6.7	-1.1	11.5					
1986	3.2	3.4	3.3	1.7	2.6	5.7	5.4	6.0	6.9	5.0	-0.1	-2.2	2.2	4.9	-0.9	5.5	-0.4				
1987	3.0	3.2	3.0	1.5	2.3	5.2	4.8	5.3	6.1	4.3	-0.2	-2.0	1.6	3.6	-1.0	3.2	-0.9	-1.3			
1988	2.7	2.9	2.7	1.2	2.0	4.7	4.3	4.7	5.3	3.7	-0.4	-2.1	1.1	2.7	-1.2	1.9	-1.3	-1.7	-2.1		
1989	3.2	3.3	3.2	1.8	2.6	5.1	4.8	5.2	5.8	4.4	0.7	-0.6	2.4	3.9	0.9	3.8	1.9	2.6	4.6	11.4	
1990	2.0	2.0	1.8	0.5	1.1	3.4	3.0	3.2	3.7	2.2	-1.3	-2.7	-0.4	0.7	-2.4	-0.5	-2.9	-3.5	-4.3	-5.4	-22.1
1991	1.9	2.0	1.8	0.6	1.1	3.3	2.9	3.1	3.5	2.1	-1.1	-2.3	-0.2	0.7	-1.9	-0.3	-2.2	-2.6	-2.9	-3.1	-10.4
1992	1.3	1.4	1.2	0.0	0.5	2.5	2.1	2.2	2.5	1.1	-1.9	-3.1	-1.2	-0.5	-3.0	-1.7	-3.6	-4.1	-4.6	-5.2	-10.8
1993	1.9	2.0	1.8	0.7	1.2	3.1	2.8	3.0	3.3	2.1	-0.7	-1.7	0.1	0.9	-1.2	0.2	-1.2	-1.3	-1.3	-1.2	-4.3
1994	1.7	1.7	1.5	0.5	0.9	2.8	2.4	2.6	2.9	1.7	-0.9	-1.9	-0.2	0.5	-1.5	-0.3	-1.6	-1.7	-1.7	-1.7	-4.3
1995	1.9	1.9	1.8	0.7	1.2	3.0	2.6	2.8	3.1	2.0	-0.4	-1.3	0.3	1.0	-0.8	0.4	-0.7	-0.7	-0.7	-0.4	-2.4
1996	2.6	2.7	2.6	1.6	2.1	3.9	3.6	3.8	4.1	3.1	0.9	0.2	1.8	2.5	1.0	2.2	1.4	1.6	1.9	2.4	1.1
1997	3.0	3.1	2.9	2.0	2.5	4.2	4.0	4.2	4.5	3.6	1.5	0.9	2.4	3.1	1.8	3.0	2.3	2.5	2.9	3.4	2.5
1998	2.7	2.8	2.7	1.8	2.3	3.8	3.6	3.8	4.1	3.2	1.2	0.6	2.0	2.7	1.4	2.4	1.7	1.9	2.2	2.7	1.7
1999	4.0	4.1	4.0	3.2	3.7	5.3	5.1	5.4	5.7	5.0	3.2	2.7	4.1	4.9	3.8	5.0	4.5	4.9	5.4	6.1	5.6
2000	3.9	4.1	4.0	3.2	3.7	5.2	5.1	5.3	5.6	4.9	3.2	2.7	4.1	4.8	3.8	4.9	4.4	4.8	5.3	5.9	5.4
2001	3.2	3.3	3.2	2.4	2.8	4.3	4.1	4.2	4.5	3.8	2.1	1.6	2.9	3.5	2.4	3.4	2.9	3.1	3.4	3.8	3.2
2002	2.5	2.6	2.4	1.7	2.1	3.4	3.2	3.3	3.6	2.8	1.1	0.6	1.8	2.3	1.3	2.1	1.5	1.7	1.9	2.2	1.4
2003	3.0	3.1	3.0	2.3	2.7	4.0	3.9	4.0	4.3	3.6	2.0	1.5	2.7	3.2	2.3	3.1	2.7	2.9	3.1	3.5	2.9
2004	3.2	3.3	3.2	2.5	2.9	4.2	4.0	4.2	4.4	3.8	2.3	1.8	3.0	3.5	2.6	3.4	3.0	3.2	3.4	3.8	3.3
2005	3.7	3.8	3.7	3.1	3.5	4.7	4.6	4.8	5.0	4.4	3.0	2.6	3.7	4.3	3.4	4.3	3.9	4.1	4.4	4.8	4.4
2006	4.0	4.1	4.0	3.4	3.8	5.0	4.9	5.1	5.3	4.7	3.4	3.0	4.1	4.6	3.9	4.7	4.4	4.6	4.9	5.3	4.9
2007	4.0	4.1	4.1	3.5	3.9	5.1	4.9	5.1	5.3	4.8	3.5	3.2	4.2	4.7	4.0	4.7	4.4	4.7	5.0	5.3	5.0
2008	3.0	3.1	3.0	2.4	2.7	3.9	3.7	3.8	4.0	3.4	2.1	1.8	2.7	3.2	2.4	3.1	2.7	2.8	3.0	3.3	2.9
2009	3.7	3.8	3.7	3.1	3.5	4.6	4.5	4.6	4.8	4.3	3.1	2.7	3.7	4.2	3.5	4.1	3.8	4.0	4.3	4.6	4.2
2010	3.9	4.0	3.9	3.3	3.7	4.8	4.7	4.8	5.0	4.5	3.3	3.0	4.0	4.4	3.7	4.4	4.1	4.3	4.6	4.9	4.6

Canada Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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1971																				
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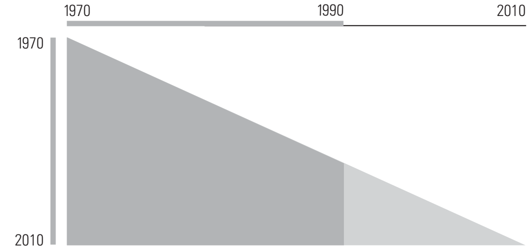
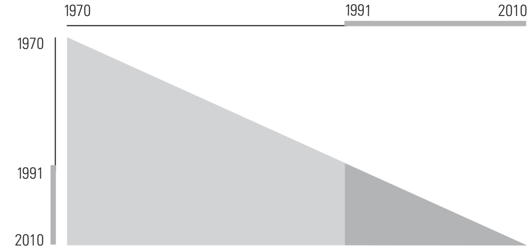
1991	1.3																			
1992	-5.1	-11.6																		
1993	1.7	1.8	15.2																	
1994	0.2	-0.2	5.4	-4.3																
1995	1.5	1.6	5.9	1.3	6.9															
1996	5.0	5.7	10.1	8.4	14.7	22.4														
1997	6.0	6.7	10.4	9.2	13.7	17.1	11.7													
1998	4.7	5.1	7.9	6.5	9.2	9.9	3.6	-4.4												
1999	8.6	9.6	12.6	12.1	15.4	17.6	15.9	18.0	40.5											
2000	8.1	8.9	11.4	10.9	13.4	14.7	12.8	13.1	21.9	3.3										
2001	5.5	5.9	7.8	6.9	8.5	8.8	6.1	4.6	7.7	-8.8	-20.8									
2002	3.4	3.6	5.1	4.0	5.0	4.8	1.8	-0.2	0.9	-12.3	-20.1	-19.4								
2003	4.8	5.1	6.6	5.8	6.9	6.9	4.7	3.5	5.1	-3.8	-6.1	1.2	21.8							
2004	5.1	5.4	6.8	6.0	7.1	7.1	5.2	4.2	5.7	-1.3	-2.4	3.7	15.2	8.7						
2005	6.2	6.5	7.9	7.3	8.3	8.5	6.9	6.3	7.9	2.4	2.3	8.0	17.2	14.9	21.0					
2006	6.6	7.0	8.3	7.8	8.8	9.0	7.6	7.2	8.6	4.0	4.2	9.2	16.3	14.5	17.4	13.7				
2007	6.6	6.9	8.2	7.7	8.6	8.7	7.5	7.1	8.3	4.3	4.5	8.7	14.3	12.4	13.6	10.0	6.2			
2008	4.3	4.4	5.4	4.8	5.4	5.3	3.9	3.2	4.0	-0.1	-0.5	2.4	6.0	2.8	1.4	-5.2	-14.7	-35.5		
2009	5.6	5.9	6.9	6.4	7.1	7.1	5.9	5.4	6.3	2.9	2.9	5.8	9.4	7.3	7.1	3.6	0.2	-2.8	29.9	
2010	5.9	6.1	7.1	6.6	7.3	7.3	6.3	5.9	6.7	3.6	3.7	6.4	9.6	7.9	7.7	5.1	2.9	1.8	20.5	11.1

Canada Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	6.2																				
1971	6.6	6.9																			
1972	13.2	16.7	26.5																		
1973	7.4	7.8	8.3	-9.9																	
1974	-1.1	-2.9	-6.2	-22.6	-35.2																
1975	0.2	-1.0	-3.0	-12.8	-14.3	6.7															
1976	0.2	-0.8	-2.3	-9.5	-9.3	3.6	0.5														
1977	-1.0	-2.1	-3.6	-9.6	-9.5	-0.9	-4.7	-10.0													
1978	0.4	-0.3	-1.3	-5.9	-5.1	2.4	1.0	1.2	12.3												
1979	4.7	4.5	4.2	1.1	2.9	10.5	11.5	15.1	27.6	43.0											
1980	5.2	5.1	4.9	2.2	3.9	10.4	11.2	13.8	21.7	26.5	9.9										
1981	2.8	2.5	2.1	-0.7	0.5	5.6	5.4	6.4	10.5	9.9	-6.7	-23.3									
1982	1.7	1.3	0.8	-1.8	-0.9	3.4	2.9	3.3	6.0	4.4	-8.4	-17.6	-11.9								
1983	3.0	2.8	2.4	0.3	1.3	5.3	5.2	5.8	8.5	7.7	-1.1	-4.8	4.4	20.7							
1984	1.6	1.3	0.8	-1.3	-0.5	2.9	2.5	2.8	4.6	3.3	-4.6	-8.3	-3.3	1.0	-18.6						
1985	1.8	1.5	1.1	-0.8	0.0	3.2	2.8	3.1	4.7	3.6	-3.0	-5.5	-1.1	2.5	-6.6	5.4					
1986	1.8	1.5	1.1	-0.7	0.0	3.0	2.6	2.8	4.3	3.2	-2.4	-4.5	-0.7	2.1	-4.1	3.1	0.8				
1987	1.9	1.7	1.4	-0.3	0.4	3.1	2.8	3.0	4.3	3.4	-1.5	-3.2	0.2	2.6	-1.9	3.7	2.8	4.8			
1988	2.2	2.0	1.7	0.1	0.8	3.4	3.1	3.3	4.5	3.7	-0.6	-1.9	1.1	3.3	-0.2	4.4	4.1	5.7	6.6		
1989	2.8	2.6	2.4	1.0	1.7	4.1	3.9	4.2	5.4	4.7	0.9	-0.1	2.8	4.9	2.3	6.5	6.7	8.7	10.7	14.8	
1990	1.6	1.4	1.1	-0.3	0.2	2.5	2.2	2.3	3.2	2.5	-1.2	-2.3	0.0	1.5	-1.2	1.7	0.9	1.0	-0.3	-3.7	-22.2
1991	1.6	1.4	1.1	-0.2	0.3	2.4	2.2	2.3	3.1	2.4	-0.9	-1.9	0.2	1.5	-0.8	1.7	1.1	1.1	0.2	-1.9	-10.3
1992	0.7	0.4	0.1	-1.2	-0.7	1.2	0.9	0.9	1.6	0.9	-2.4	-3.4	-1.6	-0.6	-2.9	-1.0	-1.9	-2.3	-3.8	-6.3	-13.4
1993	1.1	0.9	0.6	-0.6	-0.2	1.7	1.4	1.5	2.2	1.5	-1.5	-2.3	-0.6	0.4	-1.6	0.3	-0.3	-0.5	-1.4	-2.9	-7.4
1994	0.7	0.4	0.2	-1.0	-0.6	1.1	0.8	0.8	1.5	0.8	-2.0	-2.9	-1.3	-0.4	-2.3	-0.7	-1.4	-1.6	-2.5	-4.1	-7.8
1995	1.0	0.8	0.6	-0.6	-0.1	1.5	1.3	1.3	2.0	1.3	-1.3	-2.0	-0.5	0.4	-1.3	0.3	-0.2	-0.3	-1.0	-2.1	-4.9
1996	1.8	1.6	1.4	0.4	0.8	2.5	2.3	2.4	3.0	2.5	0.1	-0.5	1.0	1.9	0.5	2.1	1.8	1.9	1.6	0.9	-1.1
1997	2.0	1.8	1.6	0.6	1.1	2.7	2.5	2.6	3.2	2.7	0.5	-0.1	1.4	2.3	1.0	2.5	2.2	2.4	2.1	1.6	0.0
1998	1.6	1.4	1.2	0.2	0.6	2.1	1.9	2.0	2.5	2.1	-0.1	-0.7	0.7	1.5	0.2	1.5	1.2	1.3	0.9	0.4	-1.2
1999	3.1	3.0	2.9	2.0	2.5	4.0	3.9	4.0	4.7	4.3	2.4	2.0	3.4	4.3	3.2	4.7	4.6	4.9	4.9	4.8	3.8
2000	3.0	2.9	2.8	1.9	2.4	3.8	3.7	3.8	4.4	4.1	2.2	1.8	3.2	4.0	3.0	4.4	4.3	4.5	4.5	4.3	3.4
2001	2.1	2.0	1.8	1.0	1.4	2.7	2.6	2.7	3.2	2.8	1.0	0.5	1.7	2.4	1.4	2.6	2.4	2.5	2.4	2.1	1.0
2002	1.5	1.4	1.2	0.3	0.7	2.0	1.8	1.9	2.3	1.9	0.1	-0.3	0.8	1.4	0.4	1.4	1.2	1.2	1.0	0.6	-0.5
2003	2.9	2.8	2.6	1.9	2.3	3.6	3.4	3.5	4.1	3.7	2.1	1.8	2.9	3.6	2.8	3.9	3.8	4.0	3.9	3.7	2.9
2004	3.3	3.2	3.1	2.4	2.8	4.0	3.9	4.0	4.6	4.3	2.7	2.4	3.5	4.2	3.5	4.6	4.5	4.7	4.7	4.6	3.9
2005	3.9	3.8	3.7	3.0	3.4	4.7	4.6	4.8	5.3	5.0	3.6	3.3	4.4	5.1	4.4	5.5	5.5	5.8	5.8	5.8	5.2
2006	4.1	4.1	4.0	3.3	3.7	5.0	4.9	5.1	5.6	5.3	3.9	3.7	4.8	5.5	4.8	5.9	5.9	6.2	6.2	6.2	5.7
2007	4.7	4.6	4.6	3.9	4.4	5.6	5.5	5.7	6.2	6.0	4.7	4.5	5.5	6.2	5.6	6.7	6.8	7.0	7.2	7.2	6.8
2008	3.3	3.3	3.2	2.5	2.9	4.0	3.9	4.0	4.5	4.2	2.9	2.6	3.6	4.2	3.5	4.4	4.4	4.6	4.6	4.5	3.9
2009	4.5	4.5	4.4	3.8	4.2	5.3	5.3	5.4	5.9	5.7	4.5	4.3	5.3	5.9	5.3	6.3	6.3	6.6	6.6	6.6	6.2
2010	4.8	4.8	4.7	4.2	4.5	5.7	5.6	5.8	6.2	6.1	4.9	4.7	5.7	6.3	5.8	6.7	6.7	7.0	7.1	7.1	6.7

Canada Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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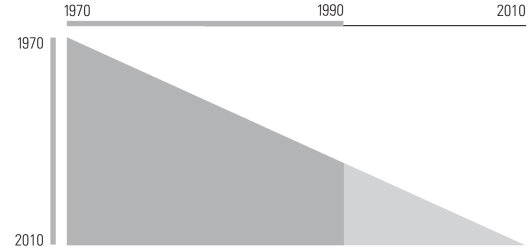
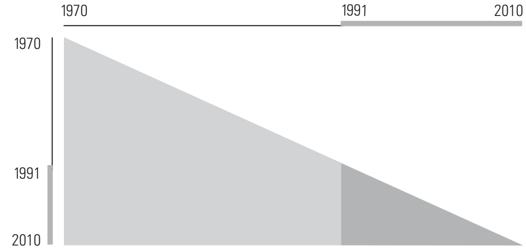
1990																				
1991	1.7																			
1992	-9.0	-19.6																		
1993	-2.4	-4.5	10.6																	
1994	-4.2	-6.2	0.5	-9.7																
1995	-1.4	-2.2	3.6	0.1	10.0															
1996	2.5	2.6	8.2	7.4	15.9	21.9														
1997	3.1	3.4	8.0	7.3	13.0	14.5	7.0													
1998	1.4	1.4	4.9	3.7	7.1	6.1	-1.8	-10.7												
1999	6.7	7.3	11.2	11.2	15.4	16.8	15.1	19.1	48.9											
2000	6.0	6.4	9.7	9.6	12.8	13.3	11.2	12.6	24.2	-0.5										
2001	3.1	3.3	5.8	5.2	7.3	6.9	3.9	3.1	7.7	-13.0	-25.4									
2002	1.3	1.3	3.4	2.6	4.1	3.3	0.2	-1.2	1.1	-14.8	-21.9	-18.4								
2003	4.9	5.2	7.4	7.1	8.9	8.8	6.9	6.9	10.5	0.8	1.3	14.6	47.7							
2004	5.8	6.1	8.2	8.0	9.8	9.8	8.3	8.4	11.6	4.2	5.3	15.6	32.6	17.5						
2005	7.1	7.4	9.5	9.4	11.2	11.3	10.1	10.5	13.5	7.6	9.2	17.9	30.0	21.2	24.9					
2006	7.5	7.8	9.8	9.7	11.4	11.5	10.4	10.8	13.5	8.4	9.9	17.0	25.9	18.6	19.1	13.4				
2007	8.5	8.9	10.8	10.8	12.4	12.6	11.7	12.2	14.7	10.5	12.0	18.3	25.6	20.1	21.0	19.0	24.6			
2008	5.4	5.6	7.2	6.9	8.1	8.0	6.8	6.8	8.5	4.0	4.6	8.9	13.5	6.6	3.9	-3.1	-11.4	-47.3		
2009	7.7	8.1	9.7	9.6	10.9	11.0	10.2	10.4	12.3	8.7	9.7	14.1	18.7	13.9	13.2	10.3	9.2	1.5	50.4	
2010	8.2	8.5	10.1	10.1	11.3	11.4	10.6	10.9	12.7	9.4	10.4	14.4	18.5	14.3	13.8	11.6	11.2	6.7	33.7	17.1

Canada Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	1.8																				
1971	5.5	9.2																			
1972	13.3	19.1	28.9																		
1973	8.0	10.0	10.4	-8.0																	
1974	-0.7	-1.3	-4.9	-21.7	-35.5																
1975	1.2	1.1	-1.0	-10.9	-12.4	10.7															
1976	1.0	0.9	-0.8	-8.2	-8.3	5.3	-0.2														
1977	0.7	0.5	-0.9	-6.9	-6.6	3.0	-0.8	-1.5													
1978	3.0	3.2	2.3	-2.1	-0.9	7.7	6.7	10.2	21.9												
1979	6.6	7.1	6.8	3.7	5.6	13.9	14.7	19.6	30.2	38.5											
1980	6.9	7.5	7.3	4.6	6.4	13.3	13.9	17.4	23.7	24.5	10.6										
1981	3.8	4.0	3.5	0.7	1.8	7.1	6.5	7.8	10.1	6.2	-9.9	-30.5									
1982	2.9	2.9	2.4	-0.3	0.6	5.1	4.3	5.0	6.3	2.4	-9.6	-19.6	-8.8								
1983	4.4	4.6	4.2	1.9	2.9	7.2	6.7	7.7	9.3	6.8	-1.2	-5.1	7.6	24.0							
1984	3.2	3.3	2.8	0.7	1.5	5.2	4.5	5.1	6.1	3.4	-3.6	-7.1	0.7	5.4	-13.1						
1985	3.8	3.9	3.6	1.6	2.4	5.9	5.4	6.0	6.9	4.8	-0.8	-3.1	3.8	8.0	-0.1	13.0					
1986	3.6	3.7	3.3	1.5	2.2	5.4	4.9	5.4	6.2	4.2	-0.7	-2.6	3.0	5.9	-0.1	6.4	-0.1				
1987	3.4	3.5	3.1	1.4	2.0	4.9	4.4	4.9	5.5	3.7	-0.7	-2.3	2.4	4.7	-0.2	4.2	-0.2	-0.4			
1988	3.1	3.2	2.8	1.2	1.8	4.5	4.0	4.3	4.9	3.2	-0.8	-2.2	1.8	3.6	-0.5	2.7	-0.7	-1.0	-1.6		
1989	3.4	3.5	3.1	1.6	2.2	4.7	4.3	4.7	5.2	3.7	0.2	-1.0	2.7	4.4	1.1	3.9	1.7	2.3	3.6	8.8	
1990	2.0	2.0	1.6	0.1	0.6	2.8	2.3	2.5	2.8	1.2	-2.2	-3.5	-0.5	0.6	-2.8	-1.0	-3.8	-4.8	-6.2	-8.5	-25.9
1991	2.0	2.0	1.6	0.2	0.7	2.8	2.3	2.5	2.7	1.3	-1.8	-3.0	-0.2	0.8	-2.2	-0.6	-2.8	-3.4	-4.1	-5.0	-11.9
1992	1.5	1.5	1.1	-0.3	0.1	2.1	1.6	1.7	1.9	0.5	-2.4	-3.5	-1.1	-0.3	-3.0	-1.7	-3.8	-4.4	-5.2	-6.1	-11.1
1993	2.2	2.2	1.9	0.6	1.0	3.0	2.5	2.7	2.9	1.7	-0.9	-1.8	0.6	1.4	-0.9	0.5	-1.1	-1.2	-1.3	-1.3	-3.8
1994	2.0	2.0	1.7	0.5	0.9	2.7	2.3	2.4	2.7	1.4	-1.0	-1.9	0.4	1.1	-1.0	0.2	-1.2	-1.3	-1.4	-1.4	-3.4
1995	2.3	2.3	2.0	0.8	1.2	3.0	2.6	2.7	3.0	1.9	-0.4	-1.2	0.9	1.7	-0.2	1.0	-0.2	-0.2	-0.2	0.0	-1.5
1996	3.1	3.2	2.9	1.9	2.3	4.0	3.7	3.9	4.2	3.2	1.1	0.5	2.6	3.4	1.8	3.0	2.1	2.3	2.7	3.2	2.4
1997	3.6	3.6	3.4	2.4	2.8	4.5	4.2	4.4	4.7	3.8	1.9	1.4	3.3	4.2	2.7	4.0	3.2	3.5	3.9	4.5	4.0
1998	3.3	3.4	3.1	2.2	2.6	4.1	3.9	4.0	4.3	3.4	1.6	1.1	2.9	3.7	2.3	3.4	2.7	2.9	3.2	3.7	3.1
1999	4.6	4.7	4.5	3.6	4.0	5.6	5.4	5.7	6.0	5.2	3.6	3.2	5.1	5.9	4.7	5.9	5.4	5.9	6.4	7.1	6.9
2000	4.5	4.6	4.5	3.6	4.0	5.5	5.3	5.6	5.9	5.2	3.6	3.2	5.0	5.8	4.7	5.8	5.3	5.7	6.2	6.8	6.6
2001	3.8	3.9	3.7	2.8	3.2	4.6	4.4	4.6	4.8	4.1	2.5	2.1	3.8	4.4	3.4	4.3	3.8	4.0	4.4	4.8	4.5
2002	3.2	3.2	3.0	2.2	2.5	3.9	3.6	3.8	4.0	3.2	1.7	1.3	2.8	3.4	2.3	3.2	2.6	2.8	3.0	3.3	2.9
2003	3.8	3.9	3.7	2.9	3.2	4.6	4.4	4.5	4.8	4.1	2.6	2.3	3.8	4.4	3.4	4.3	3.8	4.0	4.3	4.7	4.4
2004	4.0	4.1	3.9	3.2	3.5	4.8	4.6	4.8	5.0	4.4	3.0	2.7	4.1	4.7	3.8	4.6	4.2	4.4	4.7	5.1	4.9
2005	4.6	4.6	4.5	3.8	4.1	5.4	5.2	5.4	5.7	5.1	3.8	3.5	4.9	5.5	4.7	5.5	5.1	5.4	5.7	6.2	6.0
2006	4.8	4.9	4.8	4.1	4.4	5.7	5.5	5.7	5.9	5.4	4.1	3.9	5.3	5.9	5.1	5.9	5.6	5.8	6.2	6.6	6.5
2007	4.8	4.9	4.8	4.1	4.5	5.7	5.5	5.7	5.9	5.4	4.2	4.0	5.3	5.9	5.1	5.9	5.6	5.9	6.2	6.6	6.5
2008	3.8	3.9	3.8	3.1	3.4	4.5	4.3	4.5	4.7	4.1	2.9	2.6	3.8	4.3	3.5	4.2	3.9	4.0	4.3	4.5	4.3
2009	4.6	4.6	4.5	3.9	4.2	5.3	5.2	5.3	5.6	5.0	3.9	3.7	4.9	5.4	4.7	5.4	5.1	5.3	5.6	5.9	5.8
2010	4.8	4.9	4.8	4.1	4.5	5.6	5.4	5.6	5.8	5.3	4.2	4.0	5.2	5.7	5.0	5.7	5.5	5.7	6.0	6.3	6.2

Canada Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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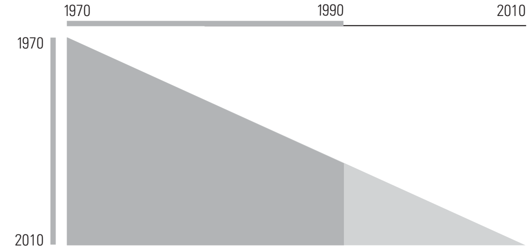
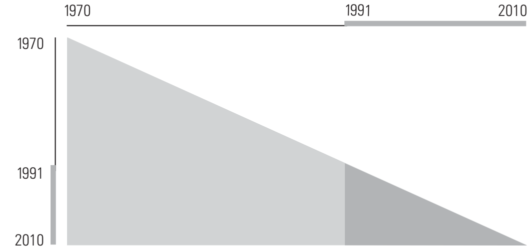
1991	2.1																			
1992	-3.7	-9.6																		
1993	3.6	4.3	18.2																	
1994	2.2	2.2	8.1	-2.0																
1995	3.4	3.8	8.2	3.2	8.5															
1996	7.1	8.1	12.5	10.6	16.9	25.4														
1997	8.2	9.3	13.0	11.7	16.3	20.3	15.2													
1998	6.8	7.4	10.3	8.7	11.3	12.3	5.8	-3.6												
1999	10.6	11.6	14.7	14.1	17.3	19.5	17.5	18.7	41.1											
2000	9.9	10.8	13.3	12.6	15.0	16.3	14.1	13.7	22.4	3.7										
2001	7.2	7.8	9.7	8.6	10.1	10.4	7.4	5.5	8.5	-7.8	-19.2									
2002	5.3	5.6	7.1	5.8	6.8	6.6	3.5	1.1	2.3	-10.6	-17.7	-16.2								
2003	6.7	7.1	8.6	7.7	8.8	8.8	6.4	5.0	6.7	-1.9	-3.8	4.0	24.2							
2004	7.1	7.5	8.9	8.0	9.0	9.1	7.1	5.9	7.5	0.8	0.1	6.5	17.9	11.6						
2005	8.1	8.6	10.0	9.3	10.3	10.5	8.8	8.0	9.7	4.5	4.6	10.6	19.6	17.3	22.9					
2006	8.5	8.9	10.2	9.6	10.6	10.8	9.3	8.7	10.2	5.8	6.2	11.3	18.1	16.1	18.4	13.8				
2007	8.4	8.7	10.0	9.4	10.3	10.4	9.1	8.4	9.8	5.9	6.2	10.4	15.7	13.6	14.3	10.0	6.2			
2008	6.0	6.2	7.2	6.5	7.1	7.0	5.5	4.6	5.4	1.4	1.1	4.1	7.4	4.1	2.2	-4.7	-13.9	-34.1		
2009	7.4	7.7	8.7	8.2	8.8	8.9	7.6	7.0	7.9	4.6	4.7	7.7	11.1	9.0	8.4	4.8	1.8	-0.4	33.2	
2010	7.8	8.1	9.1	8.5	9.2	9.2	8.1	7.5	8.5	5.5	5.7	8.4	11.5	9.7	9.4	6.7	4.9	4.5	23.8	14.4

Canada Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	1.9																				
1971	5.6	9.3																			
1972	13.4	19.2	29.1																		
1973	8.1	10.1	10.5	-8.0																	
1974	-0.7	-1.3	-4.8	-21.8	-35.6																
1975	1.2	1.0	-1.0	-11.1	-12.6	10.4															
1976	1.0	0.8	-0.9	-8.3	-8.5	5.1	-0.2														
1977	0.7	0.5	-0.9	-7.0	-6.7	2.9	-0.8	-1.4													
1978	2.9	3.0	2.1	-2.4	-1.3	7.3	6.2	9.4	20.2												
1979	6.5	7.0	6.7	3.5	5.4	13.6	14.4	19.3	29.6	39.1											
1980	6.8	7.3	7.1	4.4	6.1	13.1	13.6	17.1	23.2	24.7	10.4										
1981	3.7	3.9	3.3	0.5	1.5	6.8	6.2	7.5	9.7	6.2	-10.2	-30.7									
1982	2.8	2.8	2.2	-0.4	0.4	4.9	4.1	4.8	6.1	2.6	-9.6	-19.6	-8.5								
1983	4.3	4.4	4.0	1.8	2.7	7.0	6.6	7.5	9.0	6.8	-1.3	-5.2	7.6	23.7							
1984	3.2	3.2	2.8	0.6	1.4	5.1	4.5	5.0	6.0	3.6	-3.5	-7.0	1.0	5.7	-12.3						
1985	3.7	3.8	3.5	1.5	2.3	5.7	5.2	5.8	6.8	4.8	-0.9	-3.1	3.8	7.9	-0.1	12.2					
1986	3.5	3.6	3.2	1.4	2.1	5.2	4.8	5.3	6.0	4.2	-0.8	-2.6	3.0	5.9	-0.1	6.1	-0.1				
1987	3.3	3.4	3.0	1.2	1.9	4.8	4.3	4.7	5.4	3.7	-0.7	-2.3	2.4	4.6	-0.2	3.9	-0.3	-0.4			
1988	3.0	3.1	2.7	1.1	1.7	4.3	3.9	4.2	4.7	3.2	-0.8	-2.2	1.8	3.6	-0.5	2.5	-0.8	-1.1	-1.8		
1989	3.3	3.4	3.1	1.5	2.1	4.6	4.2	4.6	5.1	3.7	0.2	-1.0	2.7	4.4	1.1	3.8	1.7	2.3	3.7	9.1	
1990	1.9	1.9	1.5	0.0	0.5	2.7	2.2	2.4	2.7	1.2	-2.2	-3.5	-0.4	0.6	-2.7	-1.1	-3.8	-4.7	-6.2	-8.4	-25.8
1991	1.9	1.9	1.6	0.1	0.6	2.7	2.2	2.4	2.7	1.3	-1.8	-3.0	-0.2	0.7	-2.1	-0.7	-2.8	-3.4	-4.1	-4.9	-11.9
1992	1.5	1.5	1.1	-0.3	0.1	2.1	1.6	1.7	1.9	0.6	-2.4	-3.4	-1.0	-0.2	-2.9	-1.7	-3.7	-4.2	-5.0	-5.8	-10.8
1993	2.1	2.2	1.8	0.5	1.0	2.9	2.5	2.6	2.9	1.7	-1.0	-1.8	0.6	1.4	-0.8	0.5	-1.0	-1.1	-1.3	-1.2	-3.7
1994	2.0	2.0	1.7	0.4	0.8	2.6	2.2	2.4	2.6	1.5	-1.0	-1.8	0.4	1.1	-0.9	0.2	-1.1	-1.2	-1.4	-1.3	-3.4
1995	2.2	2.3	2.0	0.8	1.2	2.9	2.6	2.7	2.9	1.9	-0.4	-1.1	1.0	1.7	-0.1	1.0	-0.1	-0.1	-0.1	0.1	-1.4
1996	3.1	3.1	2.9	1.8	2.2	3.9	3.6	3.8	4.1	3.2	1.1	0.5	2.6	3.4	1.8	3.0	2.2	2.4	2.7	3.3	2.4
1997	3.5	3.6	3.3	2.3	2.7	4.4	4.1	4.3	4.6	3.8	1.8	1.3	3.3	4.1	2.7	3.9	3.2	3.5	3.9	4.5	4.0
1998	3.3	3.3	3.1	2.1	2.5	4.1	3.8	4.0	4.2	3.4	1.6	1.1	3.0	3.7	2.3	3.4	2.7	2.9	3.2	3.7	3.1
1999	4.6	4.7	4.5	3.6	4.1	5.7	5.5	5.7	6.0	5.4	3.7	3.3	5.2	6.0	4.9	6.1	5.6	6.1	6.6	7.3	7.2
2000	4.6	4.7	4.5	3.6	4.1	5.6	5.4	5.6	5.9	5.3	3.7	3.3	5.1	5.9	4.8	5.9	5.5	5.9	6.4	7.0	6.8
2001	3.9	3.9	3.7	2.9	3.3	4.7	4.5	4.7	4.9	4.3	2.7	2.3	4.0	4.6	3.6	4.5	4.0	4.3	4.6	5.1	4.8
2002	3.2	3.3	3.1	2.2	2.6	3.9	3.7	3.9	4.1	3.4	1.8	1.5	3.0	3.6	2.5	3.3	2.8	3.0	3.2	3.6	3.1
2003	4.0	4.1	3.9	3.1	3.5	4.8	4.6	4.8	5.0	4.4	3.0	2.7	4.2	4.8	3.8	4.7	4.3	4.5	4.8	5.3	5.0
2004	4.3	4.3	4.2	3.4	3.8	5.1	4.9	5.1	5.3	4.7	3.4	3.1	4.5	5.1	4.3	5.1	4.7	5.0	5.3	5.7	5.5
2005	4.8	4.9	4.7	4.0	4.4	5.7	5.5	5.7	6.0	5.4	4.1	3.9	5.3	5.9	5.1	6.0	5.7	6.0	6.3	6.8	6.6
2006	5.0	5.1	5.0	4.3	4.7	5.9	5.8	6.0	6.2	5.7	4.5	4.3	5.7	6.3	5.5	6.3	6.0	6.4	6.7	7.2	7.1
2007	5.1	5.2	5.1	4.4	4.7	6.0	5.8	6.0	6.3	5.8	4.6	4.4	5.7	6.3	5.6	6.4	6.1	6.4	6.7	7.2	7.1
2008	4.3	4.3	4.2	3.5	3.8	5.0	4.8	5.0	5.2	4.7	3.5	3.2	4.5	5.0	4.2	4.9	4.6	4.8	5.1	5.4	5.2
2009	5.1	5.2	5.1	4.4	4.8	5.9	5.8	6.0	6.2	5.8	4.7	4.5	5.7	6.2	5.6	6.3	6.0	6.3	6.6	7.0	6.9
2010	5.4	5.4	5.3	4.7	5.1	6.2	6.1	6.3	6.5	6.1	5.0	4.8	6.0	6.6	5.9	6.6	6.4	6.7	7.0	7.4	7.3

Canada Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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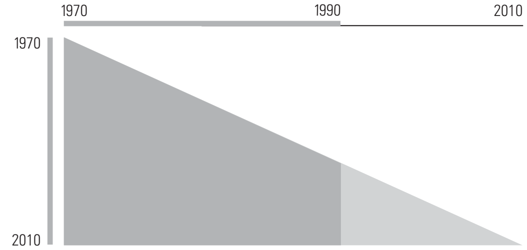
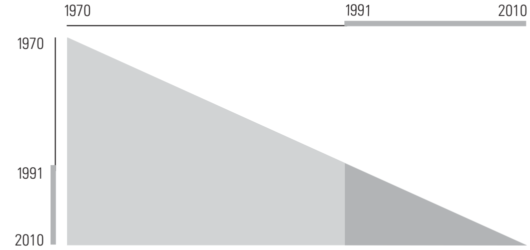
1991	2.1																			
1992	-3.3	-8.7																		
1993	3.6	4.4	17.5																	
1994	2.2	2.3	7.8	-1.9																
1995	3.5	3.9	8.1	3.4	8.7															
1996	7.2	8.2	12.4	10.7	17.0	25.3														
1997	8.2	9.2	12.8	11.6	16.2	19.9	14.5													
1998	6.8	7.4	10.1	8.6	11.3	12.1	5.6	-3.4												
1999	10.8	11.9	14.9	14.4	17.7	20.0	18.2	20.1	43.5											
2000	10.1	11.0	13.5	12.9	15.4	16.7	14.6	14.6	23.6	3.6										
2001	7.5	8.1	10.0	9.0	10.6	10.9	8.0	6.4	9.7	-7.3	-18.1									
2002	5.5	5.9	7.3	6.2	7.2	7.0	3.9	1.8	3.1	-10.3	-17.3	-16.4								
2003	7.4	7.8	9.3	8.5	9.7	9.8	7.6	6.4	8.4	-0.4	-1.8	6.4	29.3							
2004	7.7	8.2	9.6	8.9	9.9	10.1	8.2	7.3	9.1	2.2	1.8	8.5	20.9	12.5						
2005	8.8	9.3	10.7	10.1	11.2	11.4	9.9	9.3	11.1	5.8	6.2	12.3	21.8	18.1	23.7					
2006	9.1	9.6	10.9	10.4	11.4	11.7	10.3	9.8	11.5	6.9	7.5	12.6	19.8	16.7	18.7	13.8				
2007	9.0	9.4	10.6	10.2	11.1	11.3	10.0	9.6	11.0	6.9	7.4	11.7	17.3	14.3	14.9	10.5	7.3			
2008	7.0	7.2	8.2	7.6	8.3	8.3	6.9	6.2	7.1	3.1	3.0	6.0	9.8	5.9	4.2	-2.3	-10.3	-27.8		
2009	8.6	9.0	10.0	9.6	10.3	10.4	9.3	8.9	10.0	6.6	7.0	10.1	13.9	11.3	11.1	7.9	6.0	5.3	38.5	
2010	8.9	9.3	10.3	9.9	10.6	10.8	9.7	9.3	10.4	7.4	7.8	10.7	14.0	11.9	11.7	9.4	8.3	8.6	26.8	15.1

Denmark Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-16.8																				
1971	-12.0	-7.3																			
1972	23.8	44.1	95.5																		
1973	14.4	24.8	40.9	-13.7																	
1974	5.0	10.4	16.3	-23.3	-32.9																
1975	7.9	12.8	17.9	-8.0	-5.2	22.5															
1976	4.9	8.6	11.7	-9.2	-7.7	4.9	-12.7														
1977	3.3	6.1	8.4	-9.1	-7.9	0.4	-10.6	-8.4													
1978	0.6	2.8	4.3	-10.9	-10.4	-4.7	-13.8	-14.4	-20.3												
1979	-0.9	0.8	1.9	-11.5	-11.2	-6.8	-14.1	-14.6	-17.7	-15.1											
1980	0.4	2.2	3.2	-8.3	-7.5	-3.3	-8.5	-7.4	-7.1	-0.5	14.1										
1981	3.2	5.0	6.2	-3.7	-2.5	1.9	-1.6	0.7	2.9	10.7	23.6	33.1									
1982	2.8	4.4	5.5	-3.6	-2.4	1.4	-1.6	0.2	1.9	7.5	15.1	15.5	-2.0								
1983	8.3	10.2	11.7	4.1	5.8	10.1	8.6	11.6	15.0	22.1	31.4	37.1	39.1	80.2							
1984	5.1	6.6	7.7	0.4	1.7	5.1	3.2	5.2	7.1	11.7	17.0	17.8	12.7	20.0	-40.2						
1985	5.7	7.2	8.2	1.5	2.8	6.0	4.3	6.2	8.1	12.1	16.7	17.2	13.2	18.3	-12.7	14.8					
1986	3.8	5.1	5.9	-0.5	0.5	3.3	1.6	3.0	4.3	7.3	10.5	9.9	5.3	7.2	-17.2	-5.7	-26.3				
1987	2.7	3.8	4.5	-1.6	-0.7	1.8	0.0	1.2	2.2	4.7	7.1	6.1	1.7	2.4	-17.1	-9.3	-21.4	-16.6			
1988	5.8	7.1	7.9	2.4	3.5	6.1	4.8	6.3	7.6	10.4	13.3	13.2	10.3	12.4	-1.2	8.6	6.5	22.9	62.4		
1989	7.0	8.2	9.1	4.0	5.1	7.7	6.6	8.1	9.5	12.2	14.9	15.0	12.7	14.8	3.9	12.8	12.3	25.1	46.0	29.5	
1990	5.6	6.7	7.4	2.5	3.5	5.8	4.6	5.9	7.0	9.3	11.5	11.2	8.8	10.1	0.1	6.8	5.2	13.1	23.0	3.3	-22.8
1991	5.8	6.8	7.5	2.9	3.8	6.0	5.0	6.1	7.2	9.3	11.3	11.1	8.9	10.1	1.3	7.3	6.0	12.4	19.7	5.5	-6.5
1992	4.1	5.0	5.6	1.1	1.9	3.9	2.8	3.7	4.5	6.3	8.0	7.4	5.1	5.8	-2.4	2.3	0.5	5.0	9.3	-4.0	-15.2
1993	5.4	6.4	7.0	2.8	3.6	5.6	4.6	5.7	6.5	8.3	10.0	9.7	7.7	8.6	1.5	6.1	5.0	9.5	13.8	4.1	-2.3
1994	4.7	5.6	6.1	2.1	2.8	4.6	3.7	4.6	5.4	7.0	8.4	8.0	6.1	6.8	0.1	4.1	2.9	6.6	9.9	1.1	-4.5
1995	4.5	5.4	5.9	2.0	2.7	4.4	3.5	4.4	5.1	6.6	7.9	7.5	5.7	6.3	0.1	3.8	2.7	5.9	8.7	1.0	-3.7
1996	5.2	6.0	6.6	2.9	3.6	5.2	4.4	5.3	6.0	7.5	8.8	8.5	6.8	7.5	1.9	5.4	4.5	7.6	10.3	3.8	0.1
1997	6.8	7.7	8.3	4.8	5.5	7.2	6.5	7.4	8.2	9.7	11.1	10.9	9.5	10.3	5.3	8.8	8.3	11.5	14.3	8.9	6.4
1998	6.4	7.3	7.8	4.4	5.2	6.8	6.1	6.9	7.7	9.1	10.3	10.1	8.8	9.4	4.7	7.9	7.4	10.2	12.6	7.7	5.2
1999	7.1	7.9	8.5	5.3	6.0	7.5	6.9	7.8	8.5	9.9	11.1	11.0	9.8	10.5	6.1	9.2	8.8	11.5	13.8	9.4	7.4
2000	7.1	7.9	8.4	5.3	6.0	7.5	6.9	7.7	8.4	9.7	10.9	10.7	9.5	10.2	6.1	8.9	8.5	11.0	13.2	9.1	7.2
2001	6.4	7.1	7.6	4.6	5.2	6.6	6.0	6.8	7.4	8.6	9.7	9.5	8.3	8.8	4.9	7.5	7.1	9.3	11.1	7.2	5.3
2002	5.2	5.8	6.3	3.3	3.9	5.2	4.6	5.2	5.8	6.9	7.8	7.5	6.3	6.7	2.8	5.2	4.7	6.6	8.2	4.3	2.3
2003	5.6	6.3	6.7	3.9	4.4	5.7	5.1	5.8	6.3	7.4	8.4	8.1	7.0	7.4	3.8	6.1	5.6	7.5	9.0	5.4	3.7
2004	6.0	6.6	7.1	4.3	4.9	6.1	5.6	6.2	6.8	7.8	8.7	8.5	7.4	7.9	4.4	6.6	6.2	8.0	9.5	6.2	4.6
2005	6.9	7.6	8.1	5.4	6.0	7.3	6.8	7.4	8.0	9.0	10.0	9.8	8.8	9.3	6.1	8.3	8.0	9.8	11.2	8.2	6.9
2006	7.3	8.0	8.4	5.9	6.5	7.7	7.2	7.9	8.4	9.5	10.4	10.2	9.3	9.8	6.7	8.9	8.6	10.3	11.7	8.9	7.7
2007	7.4	8.0	8.5	6.0	6.6	7.8	7.3	7.9	8.5	9.5	10.4	10.2	9.3	9.8	6.9	8.9	8.6	10.3	11.6	9.0	7.8
2008	5.9	6.5	6.9	4.5	5.0	6.1	5.6	6.2	6.6	7.5	8.3	8.1	7.2	7.5	4.6	6.5	6.1	7.6	8.8	6.1	4.8
2009	6.5	7.1	7.5	5.1	5.6	6.7	6.3	6.9	7.3	8.2	9.0	8.8	8.0	8.3	5.6	7.4	7.1	8.5	9.7	7.2	6.1
2010	7.3	7.9	8.3	6.0	6.5	7.6	7.2	7.8	8.2	9.1	9.9	9.8	9.0	9.4	6.7	8.6	8.3	9.7	10.9	8.5	7.5

Denmark Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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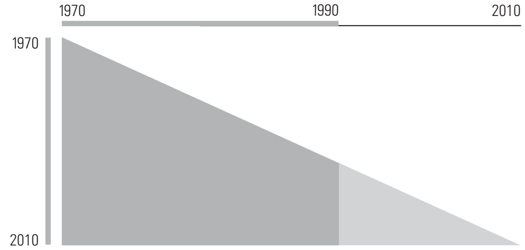
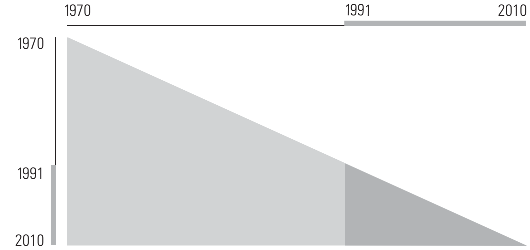
1990																				
1991	9.8																			
1992	-11.4	-32.5																		
1993	4.6	2.0	36.4																	
1994	0.1	-3.2	11.5	-13.5																
1995	0.1	-2.3	7.7	-6.7	0.2															
1996	3.9	2.7	11.5	3.2	11.6	23.0														
1997	10.5	10.6	19.3	15.0	24.5	36.6	50.3													
1998	8.7	8.6	15.5	11.3	17.4	23.2	23.3	-3.7												
1999	10.7	10.9	17.0	13.8	19.3	24.1	24.4	11.5	26.6											
2000	10.2	10.3	15.6	12.6	17.0	20.3	19.7	9.5	16.0	5.5										
2001	7.9	7.7	12.2	9.1	12.4	14.4	12.7	3.3	5.6	-4.9	-15.2									
2002	4.4	4.0	7.6	4.4	6.6	7.6	5.0	-4.1	-4.2	-14.4	-24.4	-33.5								
2003	5.7	5.4	8.8	6.1	8.2	9.2	7.3	0.1	0.8	-5.6	-9.3	-6.3	20.9							
2004	6.6	6.3	9.5	7.1	9.2	10.2	8.6	2.6	3.6	-1.0	-2.6	1.7	19.3	17.6						
2005	8.9	8.8	12.0	9.9	12.1	13.3	12.2	7.4	9.0	6.1	6.2	11.6	26.6	29.4	41.2					
2006	9.6	9.6	12.6	10.8	12.8	14.0	13.1	8.9	10.5	8.2	8.7	13.5	25.2	26.6	31.2	21.1				
2007	9.6	9.6	12.4	10.7	12.6	13.6	12.8	9.0	10.4	8.4	8.8	12.8	22.1	22.4	24.0	15.4	9.7			
2008	6.4	6.2	8.6	6.7	8.2	8.8	7.6	3.7	4.5	2.0	1.6	4.0	10.2	8.1	5.7	-6.1	-19.7	-49.0		
2009	7.6	7.5	9.8	8.1	9.6	10.3	9.3	5.9	6.7	4.7	4.7	7.1	13.0	11.6	10.4	2.7	-3.4	-9.9	29.2	
2010	9.1	9.0	11.3	9.9	11.3	12.1	11.3	8.3	9.3	7.7	7.9	10.5	16.0	15.3	14.9	9.7	6.8	5.8	33.3	37.3

Denmark Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-16.8																				
1971	-9.2	-1.7																			
1972	27.7	50.0	101.7																		
1973	19.3	31.3	47.8	-6.1																	
1974	10.4	17.2	23.4	-15.7	-25.3																
1975	10.6	16.1	20.6	-6.4	-6.6	12.0															
1976	8.1	12.3	15.1	-6.5	-6.7	2.6	-6.8														
1977	6.1	9.4	11.2	-6.9	-7.1	-1.0	-7.6	-8.3													
1978	4.4	7.0	8.2	-7.3	-7.6	-3.2	-8.2	-8.9	-9.6												
1979	2.0	4.1	4.8	-9.1	-9.6	-6.4	-11.0	-12.4	-14.5	-19.5											
1980	2.0	3.8	4.4	-7.7	-7.9	-5.1	-8.5	-8.9	-9.1	-8.8	1.8										
1981	2.6	4.3	4.9	-5.8	-5.8	-3.0	-5.5	-5.2	-4.5	-2.8	5.5	9.3									
1982	1.3	2.8	3.2	-6.7	-6.7	-4.4	-6.8	-6.8	-6.5	-5.7	-1.1	-2.6	-14.4								
1983	5.0	6.6	7.3	-1.3	-0.8	2.0	0.7	1.8	3.4	6.0	12.4	16.0	19.3	53.0							
1984	1.5	2.8	3.1	-5.1	-5.0	-3.0	-4.7	-4.4	-3.8	-2.9	0.4	0.1	-3.0	2.7	-47.6						
1985	4.1	5.5	6.0	-1.3	-0.9	1.3	0.2	1.0	2.2	3.8	7.7	8.9	8.8	16.5	-1.7	44.2					
1986	3.3	4.6	5.0	-1.9	-1.6	0.4	-0.7	-0.1	0.8	2.1	5.2	5.8	5.1	9.9	-4.4	17.1	-9.9				
1987	3.2	4.4	4.7	-1.7	-1.4	0.4	-0.6	0.0	0.8	2.0	4.7	5.1	4.4	8.2	-3.0	11.8	-4.4	1.2			
1988	5.3	6.5	7.0	1.1	1.6	3.5	2.8	3.6	4.7	6.1	9.0	9.9	10.0	14.0	6.2	19.7	11.5	22.2	43.3		
1989	6.8	8.0	8.6	3.1	3.7	5.6	5.1	6.0	7.2	8.8	11.6	12.7	13.1	17.0	11.0	22.7	17.4	26.5	39.1	35.0	
1990	5.9	7.0	7.5	2.2	2.7	4.5	4.0	4.7	5.7	7.0	9.4	10.2	10.3	13.4	7.7	16.9	11.5	16.8	22.1	11.4	-12.1
1991	5.9	7.0	7.5	2.5	3.0	4.6	4.2	4.9	5.9	7.1	9.3	9.9	10.0	12.7	7.7	15.6	10.8	15.0	18.4	10.1	-2.3
1992	4.1	5.0	5.4	0.6	0.9	2.4	1.8	2.3	3.0	3.9	5.7	6.1	5.8	7.8	2.8	9.0	4.0	6.4	7.4	-1.6	-13.8
1993	5.0	6.0	6.3	1.8	2.2	3.6	3.2	3.8	4.5	5.4	7.2	7.6	7.5	9.5	5.1	11.0	6.8	9.2	10.6	4.1	-3.7
1994	4.7	5.6	5.9	1.5	1.9	3.3	2.8	3.3	4.0	4.9	6.5	6.8	6.6	8.4	4.3	9.5	5.7	7.6	8.6	2.8	-3.7
1995	4.9	5.8	6.1	1.9	2.3	3.6	3.2	3.7	4.4	5.2	6.7	7.0	6.9	8.5	4.8	9.6	6.1	7.9	8.7	3.8	-1.4
1996	5.3	6.1	6.4	2.5	2.8	4.1	3.7	4.3	4.9	5.7	7.2	7.5	7.4	9.0	5.6	10.0	6.9	8.6	9.4	5.2	1.0
1997	6.2	7.0	7.3	3.6	4.0	5.2	4.9	5.5	6.2	7.0	8.5	8.9	8.8	10.4	7.3	11.6	8.8	10.6	11.5	8.0	4.6
1998	6.1	6.9	7.2	3.6	4.0	5.2	4.9	5.4	6.1	6.8	8.2	8.6	8.5	10.0	7.1	11.0	8.5	10.0	10.8	7.5	4.5
1999	6.2	7.0	7.3	3.8	4.1	5.3	5.0	5.6	6.2	6.9	8.3	8.6	8.6	9.9	7.2	10.9	8.5	9.9	10.6	7.7	4.9
2000	5.9	6.7	7.0	3.6	3.9	5.1	4.8	5.3	5.9	6.6	7.8	8.1	8.0	9.3	6.7	10.1	7.8	9.1	9.7	6.9	4.3
2001	5.1	5.8	6.1	2.8	3.1	4.1	3.8	4.3	4.8	5.4	6.5	6.8	6.6	7.8	5.2	8.3	6.1	7.2	7.6	4.9	2.4
2002	4.3	5.0	5.2	2.0	2.2	3.2	2.9	3.3	3.7	4.3	5.3	5.5	5.3	6.3	3.8	6.7	4.5	5.4	5.7	3.0	0.5
2003	5.5	6.2	6.4	3.3	3.7	4.7	4.4	4.8	5.3	5.9	7.0	7.2	7.1	8.1	5.9	8.7	6.7	7.7	8.1	5.7	3.7
2004	6.1	6.8	7.0	4.1	4.4	5.4	5.2	5.6	6.1	6.7	7.8	8.0	8.0	9.0	6.9	9.6	7.8	8.8	9.2	7.1	5.2
2005	6.6	7.2	7.5	4.6	5.0	6.0	5.8	6.2	6.7	7.3	8.3	8.6	8.6	9.6	7.6	10.2	8.5	9.5	10.0	8.0	6.3
2006	7.3	8.0	8.3	5.5	5.9	6.9	6.7	7.2	7.7	8.3	9.3	9.6	9.6	10.6	8.8	11.4	9.8	10.8	11.3	9.5	8.0
2007	7.7	8.4	8.7	6.0	6.3	7.3	7.2	7.6	8.1	8.8	9.8	10.1	10.1	11.1	9.3	11.8	10.3	11.3	11.8	10.1	8.7
2008	6.2	6.8	7.0	4.4	4.7	5.6	5.4	5.8	6.2	6.8	7.7	7.9	7.8	8.7	6.9	9.2	7.6	8.4	8.8	7.1	5.6
2009	6.9	7.5	7.7	5.2	5.5	6.4	6.2	6.6	7.0	7.6	8.5	8.7	8.7	9.6	7.9	10.1	8.7	9.5	9.9	8.3	6.9
2010	7.4	8.0	8.2	5.8	6.1	7.0	6.8	7.2	7.7	8.2	9.1	9.4	9.4	10.2	8.6	10.8	9.5	10.3	10.7	9.2	7.9

Denmark Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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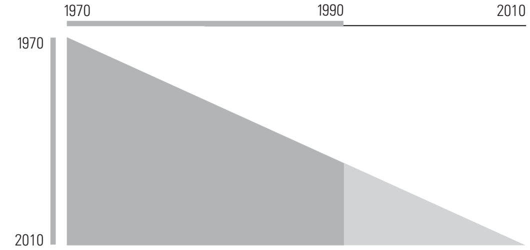
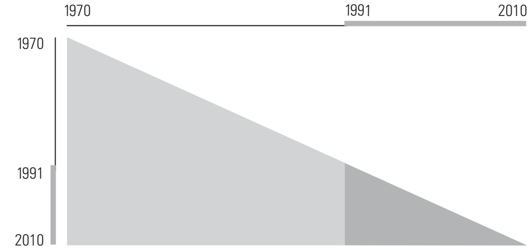
1990																				
1991	7.5																			
1992	-14.6	-36.7																		
1993	-0.9	-5.0	26.6																	
1994	-1.5	-4.6	11.5	-3.6																
1995	0.7	-0.9	11.0	3.2	9.9															
1996	3.1	2.3	12.0	7.1	12.5	15.1														
1997	7.0	6.9	15.6	12.9	18.3	22.5	30.0													
1998	6.6	6.4	13.6	11.0	14.7	16.3	16.9	3.8												
1999	6.8	6.7	12.9	10.7	13.5	14.4	14.2	6.3	8.9											
2000	6.0	5.8	11.1	8.9	11.0	11.2	10.3	3.7	3.7	-1.5										
2001	3.7	3.3	7.7	5.4	6.6	6.1	4.3	-2.1	-4.1	-10.5	-19.6									
2002	1.6	1.0	4.8	2.4	3.1	2.2	0.0	-6.0	-8.4	-14.2	-20.6	-21.5								
2003	4.9	4.7	8.4	6.6	7.7	7.4	6.4	2.4	2.2	0.5	1.1	11.5	44.5							
2004	6.4	6.4	10.0	8.4	9.6	9.6	8.9	5.9	6.3	5.8	7.6	16.6	35.7	26.9						
2005	7.5	7.5	10.9	9.6	10.8	10.9	10.5	8.0	8.7	8.6	10.6	18.2	31.4	24.9	22.9					
2006	9.3	9.4	12.7	11.6	12.9	13.1	12.9	11.0	12.0	12.4	14.7	21.6	32.3	28.3	29.0	35.1				
2007	10.0	10.1	13.2	12.3	13.5	13.8	13.7	12.1	13.0	13.5	15.7	21.5	30.1	26.6	26.4	28.2	21.4			
2008	6.6	6.5	9.2	8.1	8.9	8.8	8.3	6.3	6.6	6.3	7.3	11.1	16.6	11.0	7.0	1.8	-14.9	-51.1		
2009	7.9	8.0	10.6	9.6	10.5	10.5	10.2	8.5	8.9	8.9	10.1	13.8	18.9	14.6	12.1	9.4	0.9	-9.3	32.5	
2010	8.9	9.0	11.6	10.7	11.6	11.7	11.4	10.0	10.5	10.7	11.9	15.4	20.0	16.5	14.8	13.2	7.7	3.1	30.2	28.0

Denmark Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-16.0																				
1971	-10.1	-4.3																			
1972	26.0	47.0	98.2																		
1973	16.8	27.7	43.6	-10.9																	
1974	7.3	13.1	18.9	-20.8	-30.6																
1975	10.6	16.0	21.0	-4.7	-1.6	27.4															
1976	7.9	11.9	15.1	-5.7	-4.0	9.4	-8.7														
1977	5.9	9.1	11.3	-6.1	-4.9	3.7	-8.1	-7.6													
1978	3.9	6.4	7.9	-7.1	-6.4	-0.3	-9.6	-10.0	-12.5												
1979	2.8	4.9	6.1	-7.1	-6.5	-1.7	-8.9	-9.0	-9.7	-7.0											
1980	4.4	6.4	7.6	-3.7	-2.7	1.9	-3.2	-1.8	0.1	6.4	19.8										
1981	7.4	9.5	10.9	1.2	2.7	7.5	4.1	6.7	10.3	17.9	30.3	40.7									
1982	7.3	9.2	10.5	1.7	3.1	7.3	4.4	6.6	9.4	14.9	22.2	23.4	6.1								
1983	13.3	15.5	17.2	9.8	11.9	16.6	15.3	18.7	23.0	30.1	39.4	46.0	48.6	91.1							
1984	10.1	12.0	13.3	6.2	7.7	11.6	9.8	12.1	15.0	19.5	24.8	26.1	21.2	28.7	-33.6						
1985	10.8	12.6	13.8	7.3	8.9	12.4	11.0	13.1	15.7	19.7	24.2	25.1	21.2	26.2	-6.2	21.1					
1986	8.8	10.4	11.3	5.1	6.4	9.4	7.8	9.5	11.4	14.3	17.4	17.0	12.2	13.7	-12.0	-1.3	-23.6				
1987	7.6	9.0	9.8	3.9	5.0	7.7	6.1	7.4	8.9	11.3	13.6	12.7	8.0	8.4	-12.2	-5.1	-18.2	-12.7			
1988	10.7	12.2	13.1	7.8	9.1	11.9	10.7	12.3	14.1	16.8	19.4	19.4	16.3	18.0	3.4	12.6	9.8	26.5	65.8		
1989	11.7	13.2	14.1	9.2	10.5	13.2	12.2	13.8	15.6	18.1	20.6	20.7	18.2	19.9	8.1	16.4	15.2	28.2	48.7	31.5	
1990	10.2	11.5	12.3	7.5	8.6	11.1	10.0	11.3	12.8	14.9	16.8	16.5	13.9	14.8	3.9	10.2	8.0	15.9	25.5	5.3	-20.9
1991	10.2	11.4	12.2	7.7	8.7	11.0	10.0	11.2	12.6	14.5	16.3	16.0	13.5	14.3	4.7	10.2	8.4	14.7	21.6	6.9	-5.4
1992	8.3	9.4	10.0	5.6	6.5	8.5	7.4	8.4	9.5	11.1	12.4	11.8	9.2	9.5	0.4	4.7	2.4	6.7	10.6	-3.2	-14.8
1993	9.4	10.5	11.2	7.0	7.9	9.9	9.0	10.0	11.1	12.7	14.1	13.6	11.4	11.9	4.0	8.1	6.5	10.8	14.7	4.5	-2.2
1994	8.5	9.6	10.2	6.2	7.0	8.8	7.9	8.8	9.8	11.1	12.3	11.8	9.6	9.9	2.5	6.1	4.4	8.0	10.9	1.8	-4.2
1995	8.3	9.3	9.9	6.0	6.8	8.6	7.6	8.5	9.4	10.7	11.8	11.2	9.1	9.4	2.6	5.8	4.3	7.4	9.9	2.0	-3.0
1996	9.0	10.0	10.5	6.9	7.7	9.4	8.5	9.4	10.3	11.6	12.7	12.2	10.3	10.6	4.4	7.6	6.4	9.4	11.8	5.1	1.3
1997	10.6	11.6	12.2	8.7	9.6	11.3	10.6	11.5	12.5	13.8	14.9	14.6	13.0	13.5	7.9	11.1	10.3	13.4	16.0	10.4	7.8
1998	10.2	11.1	11.7	8.3	9.1	10.8	10.0	10.9	11.8	13.0	14.0	13.7	12.1	12.5	7.2	10.2	9.3	12.1	14.3	9.2	6.7
1999	10.8	11.7	12.2	9.1	9.8	11.4	10.8	11.6	12.5	13.7	14.7	14.5	13.0	13.4	8.5	11.4	10.7	13.3	15.5	10.9	8.8
2000	10.6	11.5	12.1	9.0	9.7	11.3	10.6	11.4	12.3	13.4	14.4	14.1	12.7	13.1	8.5	11.1	10.4	12.9	14.8	10.6	8.7
2001	9.8	10.7	11.2	8.2	8.9	10.3	9.7	10.4	11.1	12.2	13.0	12.7	11.3	11.6	7.2	9.6	8.9	11.0	12.7	8.6	6.7
2002	8.6	9.4	9.8	6.8	7.5	8.8	8.1	8.8	9.4	10.3	11.1	10.7	9.3	9.4	5.1	7.3	6.5	8.4	9.8	5.8	3.8
2003	9.0	9.8	10.2	7.4	8.0	9.3	8.7	9.3	10.0	10.8	11.6	11.2	9.9	10.1	6.0	8.1	7.4	9.2	10.6	6.9	5.1
2004	9.3	10.1	10.5	7.8	8.4	9.7	9.1	9.7	10.3	11.2	11.9	11.6	10.3	10.5	6.7	8.7	8.1	9.8	11.1	7.7	6.1
2005	10.3	11.0	11.5	8.8	9.4	10.7	10.2	10.8	11.5	12.4	13.1	12.8	11.7	11.9	8.3	10.3	9.8	11.5	12.9	9.8	8.4
2006	10.6	11.3	11.8	9.2	9.8	11.1	10.6	11.2	11.8	12.7	13.4	13.2	12.1	12.3	8.9	10.9	10.4	12.1	13.4	10.5	9.2
2007	10.6	11.3	11.7	9.2	9.8	11.0	10.5	11.2	11.8	12.6	13.3	13.1	12.0	12.2	9.0	10.8	10.3	12.0	13.2	10.4	9.3
2008	9.0	9.7	10.1	7.6	8.1	9.3	8.7	9.3	9.8	10.6	11.2	10.9	9.8	9.9	6.7	8.3	7.8	9.2	10.2	7.5	6.2
2009	9.6	10.2	10.6	8.2	8.8	9.9	9.4	9.9	10.5	11.2	11.8	11.6	10.5	10.7	7.6	9.2	8.7	10.1	11.2	8.6	7.4
2010	10.3	11.0	11.4	9.1	9.6	10.7	10.3	10.8	11.4	12.1	12.7	12.5	11.5	11.7	8.8	10.4	10.0	11.4	12.4	10.0	9.0

Denmark Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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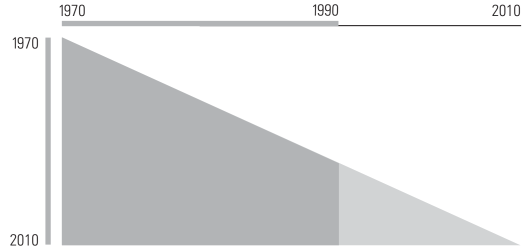
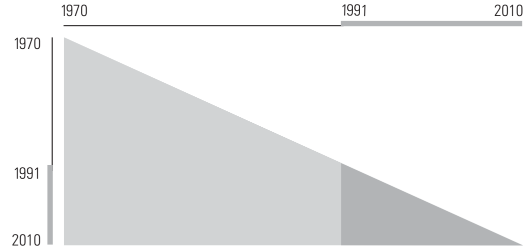
1990																				
1991	10.0																			
1992	-11.8	-33.6																		
1993	4.0	1.0	35.5																	
1994	0.0	-3.4	11.7	-12.1																
1995	0.6	-1.7	8.9	-4.4	3.2															
1996	5.0	4.0	13.3	5.9	15.0	26.7														
1997	11.9	12.2	21.3	17.8	27.8	40.0	53.4													
1998	10.1	10.1	17.4	13.8	20.3	26.0	25.6	-2.2												
1999	12.1	12.4	19.0	16.2	21.9	26.5	26.5	13.0	28.2											
2000	11.6	11.8	17.5	14.9	19.4	22.6	21.6	11.0	17.6	7.0										
2001	9.2	9.2	13.9	11.2	14.5	16.4	14.4	4.6	6.9	-3.7	-14.5									
2002	5.8	5.4	9.3	6.4	8.8	9.5	6.7	-2.7	-2.8	-13.1	-23.2	-31.8								
2003	7.1	6.9	10.6	8.1	10.3	11.2	9.0	1.6	2.4	-4.1	-7.8	-4.4	23.0							
2004	8.1	7.9	11.4	9.2	11.3	12.2	10.4	4.2	5.3	0.7	-0.8	3.7	21.5	20.0						
2005	10.4	10.4	13.8	12.0	14.2	15.3	14.0	9.1	10.7	7.7	7.9	13.5	28.6	31.4	42.8					
2006	11.1	11.2	14.4	12.7	14.8	15.9	14.8	10.5	12.1	9.8	10.2	15.2	26.9	28.3	32.4	22.0				
2007	11.0	11.1	14.1	12.5	14.4	15.4	14.3	10.4	11.8	9.8	10.2	14.3	23.5	23.7	24.9	16.0	9.9			
2008	7.7	7.6	10.1	8.4	9.9	10.4	9.1	5.0	5.8	3.3	2.8	5.3	11.5	9.2	6.4	-5.7	-19.5	-48.9		
2009	8.9	8.9	11.4	9.9	11.3	11.9	10.8	7.2	8.1	6.1	5.9	8.5	14.3	12.8	11.4	3.5	-2.6	-8.9	31.1	
2010	10.5	10.5	12.9	11.6	13.1	13.7	12.8	9.7	10.7	9.1	9.3	12.0	17.4	16.6	16.1	10.7	7.9	7.3	35.3	39.6

Denmark Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-16.0																				
1971	-10.3	-4.5																			
1972	26.9	48.4	101.3																		
1973	17.2	28.3	44.7	-11.9																	
1974	7.0	12.7	18.4	-23.0	-34.1																
1975	10.0	15.2	20.1	-7.0	-4.5	25.1															
1976	7.2	11.1	14.2	-7.5	-6.1	7.9	-9.3														
1977	5.4	8.4	10.6	-7.6	-6.5	2.7	-8.4	-7.6													
1978	3.2	5.6	7.1	-8.6	-8.0	-1.5	-10.3	-10.9	-14.1												
1979	2.2	4.3	5.3	-8.4	-7.8	-2.5	-9.4	-9.4	-10.4	-6.6											
1980	3.6	5.6	6.7	-5.1	-4.1	0.9	-4.0	-2.7	-1.0	5.5	17.7										
1981	6.1	8.1	9.4	-0.8	0.6	5.5	2.3	4.6	7.6	14.8	25.6	33.5									
1982	6.1	7.9	9.0	-0.2	1.1	5.5	2.7	4.7	7.1	12.5	18.8	19.4	5.3								
1983	11.1	13.2	14.7	6.8	8.7	13.5	12.0	15.1	18.8	25.4	33.4	38.7	41.3	77.3							
1984	8.4	10.2	11.3	3.8	5.2	9.2	7.4	9.5	11.9	16.3	20.9	21.7	17.7	23.9	-29.5						
1985	9.6	11.3	12.4	5.6	7.0	10.8	9.3	11.4	13.8	17.7	21.8	22.6	19.9	24.8	-1.5	26.5					
1986	7.3	8.8	9.6	3.1	4.3	7.5	5.8	7.4	9.0	11.9	14.6	14.0	10.2	11.4	-10.6	-1.2	-28.9				
1987	6.0	7.3	8.1	1.9	2.8	5.7	4.1	5.3	6.6	8.9	10.8	9.8	5.9	6.0	-11.8	-5.9	-22.2	-15.5			
1988	8.8	10.2	11.0	5.4	6.5	9.4	8.2	9.7	11.3	13.8	16.1	15.9	13.3	14.7	2.2	10.1	4.6	21.3	58.1		
1989	10.0	11.3	12.2	7.0	8.2	11.0	10.0	11.5	13.1	15.5	17.7	17.7	15.8	17.3	7.3	14.6	11.6	25.2	45.5	32.8	
1990	8.4	9.6	10.3	5.3	6.3	8.8	7.7	8.9	10.2	12.2	14.0	13.6	11.4	12.1	2.8	8.2	4.6	12.9	22.4	4.5	-23.8
1991	8.4	9.6	10.3	5.5	6.5	8.9	7.9	9.0	10.2	12.1	13.6	13.3	11.2	11.9	3.7	8.4	5.4	12.3	19.2	6.3	-7.0
1992	6.7	7.7	8.3	3.7	4.5	6.6	5.5	6.5	7.4	9.0	10.1	9.5	7.3	7.5	-0.2	3.5	0.2	5.0	9.1	-3.2	-15.2
1993	7.8	8.8	9.4	5.1	5.9	8.0	7.1	8.0	9.0	10.6	11.8	11.3	9.5	9.9	3.1	6.7	4.3	9.0	13.1	4.1	-3.1
1994	6.9	7.9	8.4	4.2	5.0	6.9	6.0	6.8	7.7	9.1	10.1	9.6	7.7	7.9	1.6	4.7	2.3	6.2	9.3	1.1	-5.2
1995	6.8	7.7	8.2	4.2	4.9	6.8	5.9	6.7	7.5	8.7	9.7	9.2	7.4	7.6	1.8	4.6	2.4	5.9	8.6	1.5	-3.7
1996	7.5	8.4	8.9	5.1	5.8	7.6	6.8	7.6	8.4	9.6	10.6	10.1	8.6	8.8	3.6	6.3	4.5	7.8	10.4	4.4	0.4
1997	8.9	9.8	10.3	6.7	7.5	9.3	8.6	9.4	10.3	11.6	12.6	12.3	10.9	11.3	6.6	9.4	7.9	11.3	14.0	9.1	6.1
1998	8.5	9.4	9.9	6.4	7.1	8.8	8.1	8.9	9.7	10.9	11.8	11.5	10.2	10.5	6.0	8.5	7.2	10.2	12.5	7.9	5.2
1999	9.0	9.9	10.4	7.0	7.7	9.4	8.8	9.6	10.3	11.5	12.4	12.1	10.9	11.3	7.1	9.6	8.4	11.2	13.5	9.4	7.1
2000	8.9	9.8	10.3	7.0	7.7	9.3	8.7	9.4	10.2	11.3	12.1	11.8	10.7	11.0	7.1	9.4	8.3	10.9	12.9	9.2	7.0
2001	8.2	9.0	9.5	6.3	6.9	8.5	7.8	8.5	9.2	10.2	10.9	10.6	9.5	9.7	5.9	8.0	6.9	9.3	11.0	7.4	5.3
2002	6.8	7.5	7.9	4.8	5.4	6.8	6.1	6.7	7.3	8.2	8.8	8.4	7.2	7.3	3.7	5.5	4.3	6.3	7.8	4.2	2.0
2003	7.4	8.2	8.5	5.6	6.1	7.5	6.9	7.5	8.1	9.0	9.6	9.3	8.2	8.3	4.8	6.7	5.6	7.6	9.0	5.7	3.8
2004	7.8	8.5	8.9	6.1	6.6	8.0	7.4	8.0	8.6	9.5	10.1	9.8	8.7	8.9	5.6	7.4	6.4	8.4	9.8	6.7	5.0
2005	8.7	9.4	9.8	7.0	7.6	8.9	8.4	9.0	9.6	10.5	11.1	10.9	9.9	10.1	7.1	8.8	7.9	9.9	11.3	8.5	7.0
2006	9.1	9.8	10.2	7.5	8.1	9.4	8.9	9.5	10.1	11.0	11.6	11.4	10.5	10.7	7.8	9.5	8.7	10.6	12.0	9.4	8.0
2007	9.1	9.8	10.2	7.6	8.2	9.5	9.0	9.6	10.1	11.0	11.6	11.4	10.5	10.7	8.0	9.6	8.8	10.6	11.9	9.5	8.2
2008	7.7	8.3	8.7	6.1	6.6	7.8	7.3	7.8	8.3	9.1	9.6	9.3	8.4	8.5	5.8	7.2	6.4	8.0	9.1	6.7	5.3
2009	8.3	8.9	9.3	6.8	7.3	8.5	8.0	8.5	9.0	9.8	10.3	10.1	9.2	9.4	6.8	8.2	7.5	9.0	10.2	7.9	6.6
2010	9.0	9.6	10.0	7.6	8.1	9.3	8.8	9.4	9.9	10.6	11.2	11.0	10.2	10.4	7.9	9.3	8.6	10.2	11.3	9.2	8.1

Denmark Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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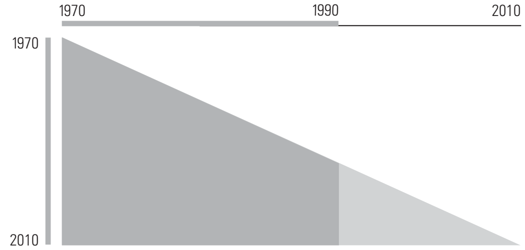
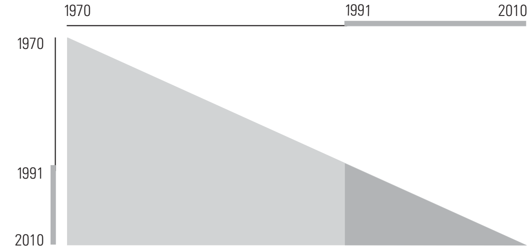
1991	9.8																			
1992	-10.8	-31.5																		
1993	3.8	0.7	33.0																	
1994	-0.5	-4.0	9.8	-13.4																
1995	0.3	-2.1	7.7	-5.0	3.5															
1996	4.4	3.3	12.0	5.0	14.3	25.0														
1997	10.4	10.4	18.8	15.3	24.9	35.6	46.2													
1998	8.8	8.6	15.3	11.8	18.1	22.9	21.9	-2.3												
1999	10.5	10.6	16.6	13.9	19.3	23.3	22.7	11.0	24.2											
2000	10.1	10.1	15.3	12.8	17.2	19.9	18.7	9.5	15.4	6.6										
2001	7.9	7.7	12.1	9.5	12.8	14.3	12.2	3.7	5.7	-3.6	-13.8									
2002	4.1	3.6	7.1	4.3	6.5	6.9	3.9	-4.6	-5.1	-14.9	-25.7	-37.5								
2003	5.9	5.6	9.0	6.6	8.8	9.5	7.3	0.8	1.4	-4.3	-7.9	-5.0	27.5							
2004	7.1	6.8	10.0	8.0	10.1	10.8	9.0	3.7	4.8	0.9	-0.6	3.8	24.5	21.6						
2005	9.1	9.0	12.1	10.4	12.6	13.5	12.2	7.9	9.4	6.9	7.0	12.2	28.8	29.4	37.2					
2006	10.0	10.0	13.0	11.5	13.6	14.5	13.4	9.8	11.3	9.4	9.9	14.7	27.7	27.8	30.9	24.5				
2007	10.1	10.1	12.9	11.4	13.4	14.2	13.2	9.9	11.3	9.6	10.1	14.0	24.3	23.6	24.2	17.7	10.9			
2008	6.9	6.7	9.1	7.6	9.1	9.5	8.2	4.7	5.4	3.3	2.9	5.3	12.5	9.5	6.5	-3.8	-18.0	-46.9		
2009	8.2	8.1	10.5	9.1	10.6	11.1	10.0	7.0	7.8	6.2	6.2	8.6	15.2	13.2	11.5	5.1	-1.4	-7.5	31.8	
2010	9.7	9.7	11.9	10.7	12.2	12.8	11.9	9.3	10.3	9.0	9.2	11.8	18.0	16.6	15.8	11.5	8.2	7.3	34.4	37.0

France Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-13.2																				
1971	-12.8	-12.4																			
1972	-3.4	1.5	15.3																		
1973	-4.8	-2.0	3.2	-8.9																	
1974	-11.6	-11.2	-10.8	-23.9	-38.9																
1975	-3.7	-1.8	0.8	-4.1	-1.6	35.7															
1976	-6.2	-5.0	-3.5	-8.2	-7.9	7.6	-20.6														
1977	-6.6	-5.6	-4.5	-8.5	-8.4	1.8	-15.1	-9.7													
1978	-1.0	0.6	2.4	0.3	2.1	12.4	4.6	17.2	44.0												
1979	0.6	2.2	4.0	2.4	4.3	12.9	7.2	16.5	29.5	15.1											
1980	0.4	1.8	3.4	1.9	3.5	10.5	5.5	12.0	19.2	6.8	-1.4										
1981	-1.6	-0.5	0.6	-1.0	0.0	5.6	0.5	4.8	8.4	-3.5	-12.8	-24.2									
1982	-1.7	-0.7	0.3	-1.2	-0.3	4.5	0.1	3.5	6.1	-3.3	-9.5	-13.5	-2.8								
1983	2.0	3.2	4.5	3.5	4.7	9.6	6.3	10.2	13.5	7.4	5.4	7.7	23.7	50.1							
1984	2.4	3.5	4.8	3.9	5.0	9.4	6.5	9.9	12.7	7.5	6.0	7.8	18.5	29.2	8.2						
1985	4.3	5.4	6.7	6.1	7.3	11.5	9.1	12.4	15.1	11.0	10.3	12.7	21.9	30.1	20.1	32.0					
1986	6.5	7.8	9.1	8.7	10.0	14.1	12.2	15.4	18.2	15.0	15.0	17.7	26.1	33.3	27.7	37.5	43.0				
1987	4.1	5.2	6.3	5.6	6.7	10.2	8.1	10.7	12.7	9.2	8.5	9.9	15.6	19.3	11.6	12.7	3.0	-36.9			
1988	6.4	7.5	8.7	8.3	9.4	12.8	11.1	13.7	15.9	13.0	12.8	14.6	20.1	24.0	18.7	21.3	17.8	5.2	47.3		
1989	7.2	8.2	9.4	9.0	10.2	13.4	11.9	14.4	16.4	13.8	13.7	15.4	20.3	23.7	19.2	21.4	18.8	10.7	34.6	21.8	
1990	5.3	6.2	7.2	6.7	7.6	10.5	8.9	11.0	12.6	9.9	9.5	10.6	14.4	16.6	11.8	12.4	8.5	-0.2	12.1	-5.6	-32.9
1991	5.5	6.4	7.4	7.0	7.8	10.6	9.0	11.0	12.5	10.0	9.6	10.6	14.1	16.0	11.7	12.2	8.9	2.1	11.9	0.0	-10.9
1992	5.3	6.2	7.1	6.7	7.5	10.1	8.6	10.4	11.7	9.4	9.0	9.8	12.9	14.5	10.5	10.8	7.8	1.9	9.7	0.3	-6.9
1993	6.1	6.9	7.8	7.4	8.2	10.7	9.3	11.1	12.4	10.3	9.9	10.8	13.7	15.2	11.7	12.1	9.6	4.9	11.8	4.7	0.5
1994	5.0	5.8	6.6	6.2	6.9	9.2	7.8	9.3	10.5	8.4	7.9	8.6	11.1	12.3	8.8	8.9	6.3	1.7	7.2	0.6	-3.7
1995	4.7	5.4	6.2	5.8	6.4	8.6	7.2	8.7	9.7	7.7	7.3	7.8	10.1	11.1	7.9	7.8	5.4	1.2	6.0	0.1	-3.5
1996	5.4	6.1	6.8	6.5	7.2	9.3	8.0	9.4	10.4	8.6	8.2	8.8	11.0	12.0	9.0	9.1	7.0	3.4	7.9	3.0	0.3
1997	6.1	6.8	7.5	7.2	7.9	9.9	8.7	10.1	11.1	9.4	9.1	9.7	11.8	12.8	10.1	10.3	8.5	5.3	9.5	5.3	3.3
1998	6.8	7.5	8.2	8.0	8.6	10.6	9.5	10.9	11.9	10.3	10.0	10.7	12.7	13.7	11.2	11.5	9.9	7.1	11.1	7.5	5.9
1999	8.1	8.9	9.6	9.4	10.1	12.1	11.1	12.5	13.5	12.1	11.9	12.6	14.6	15.7	13.5	13.9	12.6	10.2	14.2	11.2	10.1
2000	7.8	8.5	9.2	9.0	9.7	11.5	10.6	11.9	12.8	11.4	11.2	11.8	13.7	14.6	12.6	12.8	11.5	9.3	12.9	10.0	8.9
2001	6.8	7.5	8.1	7.9	8.5	10.3	9.3	10.5	11.3	9.9	9.6	10.2	11.9	12.7	10.6	10.7	9.4	7.2	10.3	7.5	6.3
2002	5.5	6.1	6.7	6.4	6.9	8.5	7.5	8.6	9.3	7.9	7.6	8.0	9.5	10.1	8.0	8.0	6.6	4.4	7.1	4.2	2.9
2003	5.7	6.3	6.9	6.6	7.1	8.7	7.7	8.8	9.5	8.1	7.8	8.2	9.7	10.3	8.3	8.3	7.0	4.9	7.5	4.8	3.6
2004	5.7	6.3	6.9	6.6	7.1	8.6	7.7	8.7	9.4	8.0	7.8	8.1	9.6	10.1	8.2	8.2	7.0	5.0	7.4	4.9	3.8
2005	6.2	6.8	7.4	7.1	7.6	9.1	8.2	9.2	9.9	8.6	8.4	8.8	10.2	10.7	8.9	9.0	7.8	6.0	8.3	6.0	5.1
2006	6.5	7.1	7.6	7.4	7.9	9.4	8.5	9.5	10.2	9.0	8.7	9.1	10.4	11.0	9.3	9.3	8.3	6.5	8.8	6.7	5.8
2007	6.3	6.9	7.4	7.2	7.6	9.1	8.2	9.2	9.8	8.6	8.4	8.7	10.0	10.5	8.9	8.9	7.8	6.2	8.3	6.3	5.4
2008	5.0	5.5	6.0	5.7	6.2	7.5	6.6	7.5	8.0	6.8	6.6	6.8	8.0	8.4	6.7	6.7	5.6	3.9	5.8	3.7	2.8
2009	5.6	6.0	6.5	6.3	6.7	8.0	7.2	8.0	8.6	7.4	7.2	7.5	8.6	9.0	7.5	7.4	6.4	4.8	6.7	4.8	3.9
2010	5.4	5.9	6.4	6.1	6.5	7.8	7.0	7.8	8.3	7.2	7.0	7.2	8.3	8.7	7.2	7.2	6.2	4.6	6.4	4.6	3.8

France Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
1972																				
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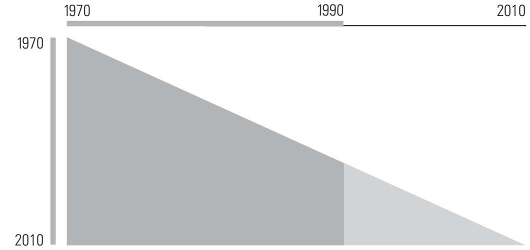
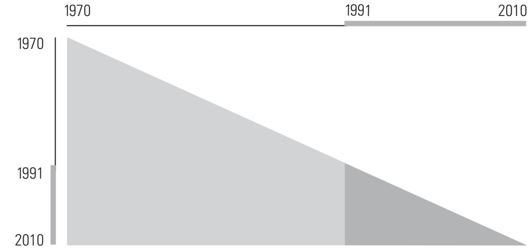
1989																				
1990																				
1991	11.2																			
1992	6.2	1.2																		
1993	11.6	11.8	22.4																	
1994	3.6	1.1	1.1	-20.3																
1995	2.4	0.2	-0.2	-11.5	-2.7															
1996	5.8	4.7	5.6	0.0	10.1	22.9														
1997	8.5	8.0	9.4	6.1	14.9	23.7	24.4													
1998	10.8	10.7	12.3	10.3	17.9	24.8	25.7	26.9												
1999	14.9	15.3	17.4	16.5	23.9	30.5	33.0	37.3	47.7											
2000	13.1	13.3	14.8	13.7	19.4	23.8	24.0	23.9	22.4	-2.9										
2001	9.8	9.7	10.6	9.2	13.4	16.0	14.7	12.2	7.3	-12.9	-22.8									
2002	5.9	5.4	5.8	4.0	7.0	8.4	5.9	2.2	-4.0	-21.2	-30.3	-37.7								
2003	6.4	6.0	6.5	4.9	7.7	9.0	7.0	4.0	-0.5	-12.6	-15.8	-12.3	13.1							
2004	6.4	6.1	6.5	5.0	7.5	8.7	6.9	4.4	0.6	-8.8	-10.3	-6.1	9.8	6.4						
2005	7.6	7.3	7.8	6.6	9.0	10.2	8.8	6.8	4.0	-3.3	-3.4	1.4	14.5	15.2	24.0					
2006	8.2	8.0	8.5	7.4	9.7	10.9	9.7	8.0	5.6	-0.4	0.1	4.7	15.2	16.0	20.7	17.5				
2007	7.7	7.4	7.8	6.8	8.9	9.9	8.7	7.1	4.9	-0.5	-0.1	3.7	11.9	11.7	13.4	8.1	-1.3			
2008	4.8	4.4	4.6	3.4	5.1	5.7	4.3	2.4	0.0	-5.3	-5.6	-3.1	2.6	0.5	-1.0	-9.3	-22.7	-44.1		
2009	5.9	5.6	5.8	4.8	6.5	7.1	5.9	4.4	2.3	-2.2	-2.2	0.4	5.9	4.7	4.3	-0.6	-6.6	-9.3	25.5	
2010	5.6	5.3	5.5	4.5	6.1	6.7	5.5	4.0	2.1	-2.0	-1.9	0.4	5.2	4.0	3.6	-0.4	-4.9	-6.1	12.9	0.3

France Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-13.3																				
1971	-10.0	-6.7																			
1972	-0.9	5.2	17.2																		
1973	-1.9	1.9	6.2	-4.7																	
1974	-8.0	-6.7	-6.7	-18.7	-32.6																
1975	-0.9	1.6	3.7	-0.8	1.2	34.9															
1976	-4.8	-3.4	-2.7	-7.7	-8.7	3.2	-28.4														
1977	-4.8	-3.5	-3.0	-7.1	-7.6	0.7	-16.4	-4.5													
1978	2.7	4.7	6.3	4.5	6.4	16.1	9.8	28.9	62.4												
1979	4.4	6.3	7.9	6.6	8.5	16.7	12.2	25.7	40.8	19.3											
1980	2.8	4.4	5.6	4.2	5.5	11.8	7.2	16.1	23.0	3.3	-12.7										
1981	-0.7	0.4	1.1	-0.7	-0.2	4.5	-0.6	4.9	7.3	-11.1	-26.3	-39.8									
1982	-2.1	-1.1	-0.6	-2.4	-2.1	1.7	-3.1	1.1	2.3	-12.8	-23.4	-28.8	-17.8								
1983	-0.4	0.6	1.2	-0.2	0.2	3.9	0.0	4.1	5.5	-5.9	-12.2	-12.0	1.9	21.6							
1984	-0.8	0.1	0.7	-0.7	-0.4	2.9	-0.7	2.8	3.8	-6.0	-11.0	-10.6	-0.8	7.7	-6.3						
1985	3.6	4.7	5.5	4.6	5.4	8.8	6.2	10.1	11.9	4.7	2.3	5.3	16.5	27.9	31.1	68.5					
1986	7.3	8.6	9.6	9.1	10.2	13.7	11.8	15.8	18.1	12.6	11.6	15.7	26.7	37.9	43.3	68.1	67.7				
1987	5.6	6.7	7.5	6.9	7.7	10.8	8.8	12.2	13.9	8.5	7.1	10.0	18.2	25.4	26.4	37.3	21.7	-24.3			
1988	6.9	8.0	8.9	8.3	9.2	12.2	10.5	13.7	15.3	10.6	9.7	12.5	20.0	26.2	27.2	35.5	24.5	3.0	30.2		
1989	7.9	9.0	9.9	9.5	10.4	13.2	11.7	14.8	16.4	12.2	11.5	14.2	20.9	26.4	27.3	34.0	25.3	11.2	28.9	27.7	
1990	6.4	7.4	8.1	7.6	8.3	10.9	9.3	12.0	13.3	9.2	8.3	10.4	15.9	20.1	19.9	24.3	15.4	2.4	11.3	1.8	-24.0
1991	6.5	7.5	8.2	7.7	8.4	10.8	9.3	11.8	13.0	9.2	8.3	10.2	15.2	18.9	18.6	22.1	14.4	3.7	10.7	4.2	-7.5
1992	6.0	6.9	7.6	7.1	7.7	9.9	8.5	10.8	11.8	8.2	7.3	9.0	13.4	16.5	16.0	18.8	11.7	2.3	7.6	2.0	-6.6
1993	6.4	7.2	7.9	7.4	8.0	10.2	8.8	11.0	12.0	8.6	7.8	9.4	13.5	16.4	15.8	18.3	12.0	4.1	8.8	4.5	-1.3
1994	5.7	6.4	7.0	6.6	7.1	9.1	7.7	9.7	10.6	7.3	6.5	7.9	11.6	14.0	13.3	15.3	9.4	2.1	5.8	1.8	-3.4
1995	5.7	6.4	7.0	6.5	7.1	8.9	7.6	9.5	10.3	7.3	6.5	7.8	11.2	13.4	12.7	14.5	9.1	2.5	5.9	2.4	-1.8
1996	6.0	6.8	7.3	6.9	7.4	9.2	8.0	9.8	10.6	7.7	7.0	8.3	11.5	13.6	13.0	14.6	9.7	3.8	7.0	4.1	0.7
1997	6.1	6.8	7.3	6.9	7.4	9.2	8.0	9.7	10.4	7.7	7.1	8.2	11.2	13.2	12.6	14.0	9.5	4.2	7.0	4.5	1.6
1998	7.2	7.9	8.4	8.1	8.6	10.3	9.2	11.0	11.7	9.2	8.6	9.8	12.7	14.6	14.2	15.6	11.6	6.9	9.7	7.7	5.5
1999	7.8	8.5	9.1	8.8	9.3	10.9	9.9	11.6	12.3	10.0	9.5	10.7	13.5	15.3	14.9	16.3	12.6	8.4	11.1	9.3	7.5
2000	7.2	7.9	8.4	8.1	8.6	10.2	9.2	10.8	11.4	9.1	8.6	9.7	12.3	14.0	13.5	14.7	11.2	7.1	9.5	7.8	6.0
2001	6.2	6.8	7.3	6.9	7.3	8.8	7.8	9.2	9.8	7.5	7.0	7.9	10.3	11.8	11.3	12.3	8.8	4.9	6.9	5.1	3.3
2002	5.2	5.8	6.2	5.8	6.2	7.5	6.5	7.9	8.4	6.1	5.5	6.4	8.6	9.9	9.3	10.1	6.7	2.9	4.7	2.9	1.0
2003	6.1	6.7	7.1	6.8	7.2	8.5	7.6	8.9	9.4	7.3	6.8	7.7	9.8	11.1	10.6	11.5	8.3	4.8	6.7	5.1	3.5
2004	6.3	6.9	7.3	7.0	7.4	8.7	7.8	9.1	9.6	7.6	7.1	8.0	10.0	11.3	10.8	11.7	8.7	5.4	7.1	5.7	4.2
2005	6.4	6.9	7.3	7.0	7.4	8.7	7.8	9.1	9.5	7.6	7.1	7.9	9.9	11.1	10.7	11.5	8.6	5.5	7.2	5.8	4.4
2006	7.0	7.6	8.0	7.7	8.1	9.4	8.6	9.8	10.3	8.4	8.0	8.8	10.8	12.0	11.6	12.4	9.7	6.8	8.4	7.2	6.0
2007	7.1	7.7	8.1	7.8	8.2	9.4	8.6	9.8	10.3	8.5	8.1	8.9	10.7	11.9	11.5	12.2	9.7	6.9	8.5	7.3	6.2
2008	5.7	6.2	6.6	6.3	6.6	7.7	6.9	8.0	8.4	6.6	6.2	6.9	8.6	9.6	9.1	9.8	7.2	4.5	5.8	4.6	3.4
2009	6.3	6.8	7.2	6.9	7.2	8.4	7.6	8.7	9.1	7.4	7.0	7.7	9.3	10.4	9.9	10.6	8.2	5.6	6.9	5.8	4.7
2010	6.0	6.5	6.8	6.6	6.9	8.0	7.2	8.2	8.6	6.9	6.5	7.2	8.8	9.8	9.3	9.9	7.6	5.1	6.4	5.3	4.2

France Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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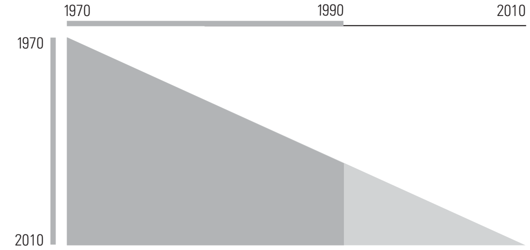
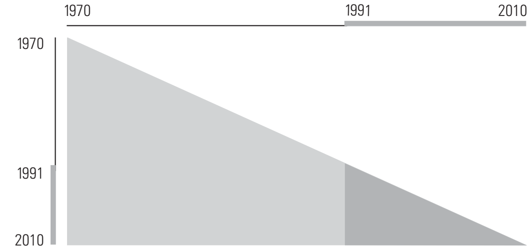
1991	9.1																			
1992	2.2	-4.8																		
1993	6.3	4.9	14.5																	
1994	1.8	-0.7	1.4	-11.8																
1995	2.7	1.0	3.0	-2.8	6.2															
1996	4.8	4.0	6.1	3.4	10.9	15.6														
1997	5.2	4.6	6.4	4.4	9.8	11.6	7.5													
1998	9.1	9.1	11.5	10.8	16.5	19.9	22.1	36.6												
1999	11.0	11.3	13.5	13.4	18.4	21.5	23.4	31.4	26.1											
2000	9.0	9.0	10.7	10.2	13.8	15.4	15.3	17.9	8.5	-9.1										
2001	5.8	5.4	6.6	5.6	8.0	8.3	6.9	6.7	-3.3	-17.9	-26.8									
2002	3.1	2.5	3.2	2.0	3.7	3.3	1.3	0.1	-9.1	-20.8	-26.7	-26.6								
2003	5.6	5.3	6.2	5.4	7.3	7.4	6.3	6.0	-0.1	-6.6	-5.8	4.7	36.0							
2004	6.2	6.0	6.9	6.2	8.0	8.2	7.3	7.3	2.4	-2.4	-0.7	8.0	25.3	14.7						
2005	6.3	6.1	7.0	6.3	8.0	8.2	7.3	7.3	3.1	-0.7	1.0	7.9	19.4	11.1	7.5					
2006	7.9	7.8	8.7	8.3	9.9	10.3	9.7	10.0	6.7	3.9	6.0	12.6	22.4	17.9	19.5	31.4				
2007	8.0	7.9	8.8	8.4	9.9	10.2	9.7	9.9	7.0	4.6	6.5	12.1	19.8	15.8	16.1	20.4	9.5			
2008	4.9	4.7	5.3	4.7	5.8	5.8	5.0	4.8	1.6	-1.1	-0.1	3.7	8.7	3.2	0.4	-2.0	-18.7	-46.8		
2009	6.2	6.1	6.7	6.2	7.4	7.5	6.9	6.8	4.1	1.9	3.2	6.9	11.7	7.6	6.2	5.9	-2.6	-8.6	29.6	
2010	5.6	5.4	6.0	5.5	6.6	6.6	6.0	5.8	3.3	1.2	2.2	5.4	9.4	5.7	4.1	3.5	-3.5	-7.8	11.7	-6.2

France Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-14.5																				
1971	-12.6	-10.8																			
1972	-2.4	3.6	18.0																		
1973	-4.3	-0.9	4.0	-10.0																	
1974	-12.1	-11.5	-11.8	-26.7	-43.3																
1975	-3.9	-1.8	0.5	-5.4	-3.0	37.3															
1976	-6.2	-4.8	-3.6	-9.0	-8.7	8.6	-20.0														
1977	-6.6	-5.5	-4.6	-9.1	-8.9	2.6	-14.7	-9.4													
1978	-0.8	0.9	2.5	0.0	2.0	13.3	5.3	17.9	45.3												
1979	0.8	2.5	4.1	2.2	4.2	13.7	7.8	17.0	30.3	15.3											
1980	0.5	2.0	3.4	1.6	3.3	11.0	5.8	12.2	19.4	6.5	-2.2										
1981	-1.7	-0.6	0.5	-1.5	-0.4	5.7	0.4	4.5	8.0	-4.4	-14.3	-26.3									
1982	-1.8	-0.8	0.1	-1.7	-0.7	4.6	-0.1	3.2	5.8	-4.1	-10.6	-14.8	-3.2								
1983	1.9	3.2	4.4	3.1	4.4	9.8	6.3	10.1	13.3	6.9	4.8	7.2	23.9	51.1							
1984	2.4	3.6	4.7	3.6	4.8	9.6	6.6	9.9	12.7	7.2	5.6	7.6	18.8	29.9	8.7						
1985	4.3	5.6	6.7	5.8	7.2	11.8	9.2	12.5	15.2	10.9	10.2	12.6	22.4	30.9	20.8	32.9					
1986	6.7	8.0	9.2	8.6	10.1	14.5	12.4	15.7	18.5	15.1	15.1	18.0	26.8	34.3	28.7	38.8	44.6				
1987	4.3	5.4	6.4	5.6	6.7	10.6	8.4	10.9	13.0	9.4	8.7	10.2	16.3	20.2	12.5	13.8	4.2	-36.3			
1988	6.6	7.8	8.9	8.3	9.6	13.3	11.5	14.1	16.3	13.4	13.2	15.1	21.0	25.0	19.8	22.6	19.2	6.4	49.1		
1989	7.4	8.5	9.6	9.1	10.3	13.9	12.2	14.7	16.7	14.1	14.0	15.8	21.0	24.5	20.0	22.3	19.7	11.4	35.2	21.2	
1990	5.4	6.4	7.3	6.7	7.7	10.9	9.1	11.2	12.8	10.1	9.6	10.8	14.9	17.2	12.3	12.9	8.9	0.0	12.1	-6.4	-34.0
1991	5.6	6.6	7.5	6.9	7.9	10.9	9.2	11.2	12.6	10.1	9.7	10.8	14.5	16.5	12.1	12.6	9.3	2.2	11.8	-0.7	-11.6
1992	5.4	6.3	7.1	6.5	7.4	10.2	8.6	10.4	11.7	9.3	8.9	9.8	13.1	14.7	10.7	10.9	7.8	1.6	9.2	-0.8	-8.1
1993	6.0	6.9	7.7	7.2	8.0	10.8	9.3	11.0	12.3	10.1	9.7	10.6	13.7	15.2	11.7	12.0	9.4	4.3	11.1	3.5	-0.9
1994	5.0	5.8	6.5	6.0	6.7	9.2	7.7	9.3	10.4	8.2	7.7	8.4	11.1	12.3	8.8	8.8	6.1	1.3	6.7	-0.4	-4.7
1995	4.7	5.5	6.2	5.6	6.3	8.7	7.3	8.7	9.7	7.6	7.2	7.8	10.2	11.3	7.9	7.9	5.4	1.0	5.7	-0.6	-4.2
1996	5.5	6.2	6.9	6.5	7.2	9.5	8.2	9.6	10.6	8.6	8.2	8.9	11.2	12.3	9.3	9.3	7.2	3.5	7.9	2.7	0.1
1997	6.2	7.0	7.7	7.3	8.0	10.2	9.0	10.4	11.4	9.6	9.3	9.9	12.2	13.2	10.5	10.7	8.8	5.6	9.8	5.4	3.4
1998	7.0	7.8	8.5	8.1	8.8	11.0	9.8	11.2	12.2	10.5	10.3	11.0	13.2	14.2	11.7	12.0	10.3	7.5	11.5	7.7	6.2
1999	8.4	9.2	9.9	9.6	10.4	12.5	11.5	12.8	13.9	12.4	12.2	13.0	15.2	16.2	14.1	14.4	13.1	10.7	14.6	11.4	10.5
2000	8.1	8.8	9.5	9.2	9.9	12.0	10.9	12.2	13.2	11.7	11.5	12.2	14.3	15.2	13.1	13.4	12.1	9.8	13.3	10.3	9.3
2001	7.1	7.8	8.4	8.1	8.8	10.7	9.7	10.8	11.7	10.2	10.0	10.6	12.4	13.2	11.1	11.3	9.9	7.6	10.8	7.8	6.7
2002	5.8	6.4	7.0	6.6	7.2	9.0	8.0	9.0	9.8	8.3	8.0	8.5	10.1	10.8	8.7	8.7	7.2	4.9	7.6	4.7	3.4
2003	6.1	6.7	7.2	6.9	7.5	9.2	8.2	9.3	10.0	8.6	8.3	8.7	10.3	11.0	9.0	9.0	7.7	5.5	8.1	5.4	4.2
2004	6.1	6.8	7.3	7.0	7.5	9.2	8.2	9.2	9.9	8.6	8.3	8.7	10.3	10.9	9.0	9.0	7.7	5.7	8.1	5.6	4.5
2005	6.7	7.3	7.8	7.5	8.1	9.7	8.8	9.8	10.5	9.2	8.9	9.4	10.9	11.5	9.7	9.7	8.6	6.7	9.1	6.7	5.8
2006	7.0	7.6	8.1	7.8	8.4	10.0	9.1	10.1	10.7	9.5	9.3	9.7	11.2	11.8	10.1	10.1	9.0	7.3	9.6	7.4	6.5
2007	6.8	7.4	7.9	7.6	8.1	9.6	8.8	9.7	10.3	9.1	8.9	9.3	10.7	11.3	9.6	9.6	8.6	6.9	9.0	6.9	6.1
2008	5.5	6.0	6.5	6.1	6.6	8.1	7.2	8.0	8.6	7.4	7.1	7.4	8.7	9.1	7.5	7.4	6.3	4.6	6.5	4.4	3.5
2009	6.0	6.6	7.0	6.7	7.2	8.6	7.8	8.6	9.2	8.0	7.8	8.1	9.4	9.8	8.3	8.2	7.2	5.6	7.5	5.5	4.7
2010	6.0	6.5	6.9	6.6	7.1	8.5	7.6	8.5	9.0	7.9	7.6	8.0	9.1	9.6	8.0	8.0	7.0	5.5	7.3	5.4	4.6

France Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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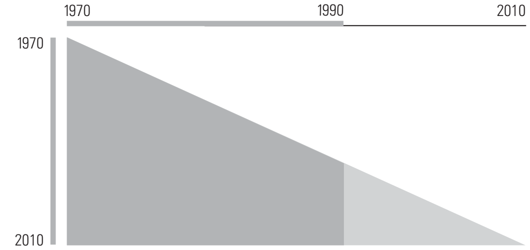
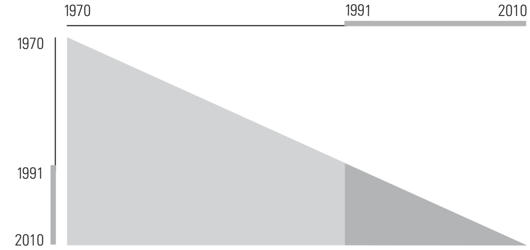
1990																				
1991	10.8																			
1992	4.9	-1.1																		
1993	10.1	9.7	20.5																	
1994	2.6	-0.2	0.3	-19.9																
1995	1.8	-0.5	-0.3	-10.6	-1.4															
1996	5.7	4.7	6.2	1.4	12.1	25.5														
1997	8.7	8.4	10.3	7.8	17.0	26.2	26.8													
1998	11.2	11.3	13.3	11.9	19.8	26.9	27.6	28.4												
1999	15.4	16.0	18.4	18.1	25.7	32.4	34.7	38.7	48.9											
2000	13.7	14.0	15.9	15.2	21.1	25.6	25.6	25.1	23.5	-1.9										
2001	10.4	10.4	11.6	10.5	14.9	17.6	16.0	13.3	8.2	-12.1	-22.4									
2002	6.5	6.1	6.8	5.3	8.5	9.9	7.3	3.4	-2.9	-20.2	-29.3	-36.2								
2003	7.2	6.9	7.6	6.3	9.2	10.5	8.4	5.3	0.7	-11.4	-14.5	-10.6	15.0							
2004	7.3	7.0	7.7	6.5	9.1	10.3	8.4	5.8	2.0	-7.4	-8.7	-4.2	11.8	8.6						
2005	8.5	8.3	9.0	8.1	10.6	11.8	10.3	8.2	5.3	-1.9	-1.9	3.2	16.3	16.9	25.3					
2006	9.1	9.0	9.7	8.8	11.2	12.4	11.1	9.3	6.9	0.9	1.4	6.2	16.8	17.4	21.8	18.2				
2007	8.5	8.3	9.0	8.1	10.3	11.3	10.0	8.3	6.0	0.7	1.0	4.9	13.2	12.7	14.1	8.5	-1.2			
2008	5.6	5.3	5.7	4.7	6.4	7.0	5.5	3.5	1.1	-4.3	-4.6	-2.0	3.7	1.4	-0.4	-8.9	-22.5	-43.8		
2009	6.7	6.5	7.0	6.1	7.9	8.5	7.2	5.6	3.5	-1.0	-0.9	1.7	7.2	5.8	5.3	0.3	-5.7	-7.9	28.0	
2010	6.5	6.3	6.7	5.9	7.5	8.1	6.9	5.4	3.4	-0.7	-0.6	1.8	6.6	5.4	4.9	0.8	-3.6	-4.4	15.3	2.7

France Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-15.3																				
1971	-12.9	-10.6																			
1972	-2.7	3.6	17.9																		
1973	-5.7	-2.5	1.6	-14.7																	
1974	-13.2	-12.7	-13.3	-28.9	-43.2																
1975	-4.7	-2.6	-0.6	-6.8	-2.9	37.4															
1976	-6.7	-5.2	-4.2	-9.7	-8.0	9.6	-18.2														
1977	-7.1	-5.9	-5.1	-9.7	-8.4	3.1	-14.0	-9.8													
1978	-0.6	1.3	2.9	0.5	3.5	15.2	7.7	20.7	51.2												
1979	1.0	2.8	4.5	2.6	5.5	15.2	9.7	19.0	33.4	15.5											
1980	0.7	2.3	3.7	2.0	4.4	12.3	7.3	13.6	21.4	6.5	-2.4										
1981	-1.0	0.3	1.4	-0.5	1.3	7.7	2.7	6.9	11.1	-2.3	-11.2	-20.0									
1982	-1.2	0.0	0.9	-0.8	0.8	6.3	1.8	5.1	8.1	-2.6	-8.7	-11.8	-3.6								
1983	1.9	3.2	4.3	3.1	4.9	10.2	6.8	10.4	13.7	6.2	3.9	6.1	19.1	41.8							
1984	2.2	3.5	4.5	3.4	5.1	9.9	6.8	10.0	12.8	6.4	4.6	6.3	15.1	24.4	7.1						
1985	4.7	6.1	7.3	6.5	8.2	12.9	10.4	13.6	16.5	11.6	10.9	13.6	22.0	30.6	25.0	42.8					
1986	7.3	8.7	10.0	9.5	11.3	15.9	13.9	17.1	20.1	16.2	16.3	19.5	27.4	35.1	32.9	45.7	48.7				
1987	4.4	5.6	6.6	5.8	7.3	11.2	9.0	11.5	13.6	9.4	8.7	10.3	15.3	19.1	13.4	15.5	1.9	-45.0			
1988	6.5	7.7	8.8	8.2	9.8	13.5	11.7	14.2	16.4	12.9	12.6	14.5	19.4	23.2	19.5	22.7	15.9	-0.4	44.1		
1989	7.3	8.5	9.5	9.0	10.5	14.1	12.4	14.8	16.9	13.7	13.6	15.3	19.7	23.1	20.0	22.5	17.5	7.1	33.1	22.1	
1990	5.1	6.1	7.0	6.4	7.6	10.8	9.0	11.0	12.6	9.4	8.8	9.9	13.3	15.4	11.6	12.3	6.2	-4.4	9.2	-8.3	-38.7
1991	5.3	6.3	7.2	6.6	7.8	10.8	9.1	10.9	12.4	9.4	8.9	10.0	13.0	14.8	11.4	12.1	6.9	-1.4	9.5	-2.0	-14.1
1992	5.1	6.0	6.8	6.2	7.3	10.2	8.6	10.2	11.6	8.7	8.2	9.1	11.7	13.3	10.1	10.5	5.9	-1.3	7.5	-1.7	-9.6
1993	5.7	6.6	7.4	6.9	7.9	10.6	9.1	10.8	12.0	9.4	9.0	9.9	12.4	13.8	11.0	11.4	7.5	1.7	9.4	2.5	-2.4
1994	4.6	5.4	6.1	5.6	6.5	9.0	7.5	8.9	10.0	7.5	6.9	7.6	9.7	10.8	8.0	8.1	4.2	-1.3	4.9	-1.6	-6.3
1995	4.3	5.1	5.8	5.3	6.2	8.5	7.1	8.4	9.4	6.9	6.4	7.0	8.9	9.9	7.2	7.3	3.7	-1.3	4.2	-1.5	-5.5
1996	5.1	5.8	6.5	6.0	6.9	9.2	7.9	9.2	10.2	7.9	7.4	8.0	9.9	10.9	8.5	8.6	5.5	1.2	6.3	1.6	-1.3
1997	5.7	6.5	7.1	6.7	7.6	9.8	8.6	9.8	10.8	8.7	8.3	8.9	10.7	11.7	9.5	9.7	7.0	3.2	8.0	4.0	1.7
1998	6.6	7.3	8.0	7.6	8.5	10.7	9.5	10.8	11.8	9.8	9.5	10.1	11.9	12.9	11.0	11.2	8.8	5.5	10.1	6.7	5.0
1999	7.7	8.5	9.2	8.9	9.8	11.9	10.8	12.1	13.1	11.3	11.1	11.8	13.5	14.5	12.8	13.2	11.1	8.2	12.6	9.8	8.6
2000	7.4	8.2	8.8	8.5	9.3	11.4	10.3	11.5	12.4	10.7	10.4	11.1	12.7	13.6	12.0	12.3	10.2	7.5	11.5	8.8	7.6
2001	6.5	7.2	7.8	7.5	8.3	10.2	9.1	10.2	11.0	9.3	9.0	9.6	11.0	11.8	10.2	10.3	8.3	5.6	9.2	6.5	5.2
2002	5.0	5.7	6.2	5.8	6.5	8.3	7.2	8.2	8.9	7.1	6.8	7.2	8.5	9.1	7.4	7.4	5.3	2.6	5.8	3.0	1.6
2003	5.4	6.1	6.6	6.2	6.9	8.6	7.6	8.6	9.3	7.6	7.3	7.7	8.9	9.5	7.9	8.0	6.0	3.5	6.6	4.1	2.8
2004	5.5	6.1	6.7	6.3	7.0	8.7	7.7	8.6	9.3	7.7	7.3	7.7	9.0	9.5	8.0	8.0	6.2	3.8	6.7	4.4	3.2
2005	6.0	6.6	7.1	6.8	7.4	9.1	8.1	9.0	9.7	8.2	7.9	8.3	9.5	10.0	8.6	8.7	7.0	4.8	7.5	5.4	4.3
2006	6.4	7.0	7.5	7.2	7.8	9.4	8.5	9.4	10.1	8.6	8.4	8.8	9.9	10.5	9.1	9.2	7.6	5.6	8.2	6.2	5.3
2007	6.2	6.8	7.2	6.9	7.6	9.1	8.2	9.1	9.7	8.3	8.0	8.4	9.5	10.0	8.7	8.8	7.2	5.2	7.8	5.8	4.9
2008	4.9	5.5	5.9	5.6	6.1	7.6	6.7	7.5	8.0	6.6	6.3	6.6	7.6	8.0	6.7	6.6	5.1	3.1	5.4	3.4	2.5
2009	5.6	6.1	6.5	6.2	6.8	8.2	7.4	8.1	8.7	7.3	7.1	7.4	8.4	8.8	7.5	7.6	6.1	4.2	6.5	4.7	3.8
2010	5.5	6.0	6.4	6.1	6.7	8.1	7.2	8.0	8.5	7.2	6.9	7.2	8.2	8.6	7.4	7.4	6.0	4.2	6.3	4.6	3.8

France Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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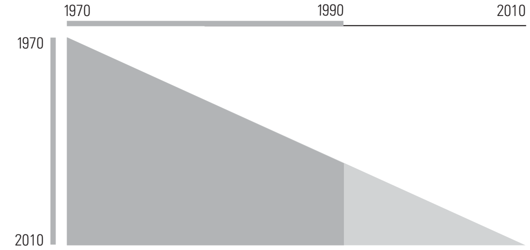
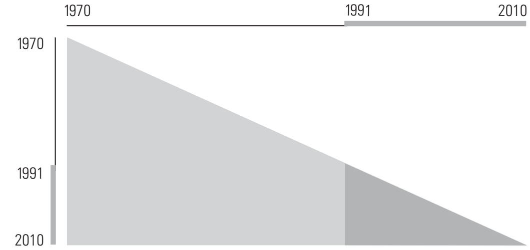
1990																				
1991	10.5																			
1992	4.9	-0.7																		
1993	9.7	9.3	19.2																	
1994	1.8	-1.1	-1.4	-22.0																
1995	1.2	-1.2	-1.4	-11.6	-1.3															
1996	4.9	3.8	4.9	0.1	11.1	23.6														
1997	7.5	7.0	8.6	5.9	15.2	23.4	23.3													
1998	10.4	10.4	12.3	10.9	19.1	25.9	27.0	30.8												
1999	13.8	14.2	16.4	15.9	23.5	29.6	31.7	35.9	40.9											
2000	12.3	12.5	14.1	13.4	19.3	23.4	23.3	23.3	19.6	-1.7										
2001	9.2	9.1	10.2	9.1	13.5	16.0	14.5	12.3	6.1	-11.3	-20.9									
2002	4.9	4.4	4.9	3.3	6.5	7.6	5.0	1.3	-6.1	-21.8	-31.8	-42.6								
2003	6.0	5.6	6.1	4.8	7.8	9.0	6.9	4.1	-1.2	-11.7	-15.0	-12.1	18.4							
2004	6.2	5.9	6.4	5.2	8.0	9.0	7.2	4.9	0.5	-7.5	-9.0	-5.0	13.8	9.1						
2005	7.2	7.0	7.6	6.6	9.2	10.2	8.7	6.9	3.5	-2.7	-2.9	1.6	16.3	15.3	21.5					
2006	8.0	7.9	8.5	7.7	10.1	11.2	9.9	8.5	5.7	0.6	1.0	5.4	17.4	17.1	21.1	20.6				
2007	7.5	7.3	7.9	7.0	9.3	10.2	8.9	7.5	4.9	0.4	0.7	4.3	13.7	12.6	13.7	9.8	-1.0			
2008	4.7	4.4	4.7	3.8	5.6	6.1	4.7	3.0	0.2	-4.3	-4.6	-2.3	4.4	1.6	-0.3	-7.5	-21.6	-42.3		
2009	6.1	5.8	6.2	5.4	7.2	7.8	6.6	5.2	2.9	-0.9	-0.8	1.7	8.0	6.3	5.7	1.7	-4.5	-6.3	29.6	
2010	5.9	5.6	6.0	5.2	6.9	7.5	6.3	5.0	2.9	-0.6	-0.5	1.8	7.3	5.7	5.2	1.9	-2.8	-3.3	16.1	2.6

Germany Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-31.7																				
1971	-14.2	3.4																			
1972	-6.7	5.8	8.2																		
1973	-12.1	-5.5	-10.0	-28.2																	
1974	-10.8	-5.5	-8.5	-16.8	-5.4																
1975	-3.6	2.1	1.7	-0.4	13.5	32.4															
1976	-4.8	-0.3	-1.0	-3.3	5.0	10.2	-12.0														
1977	-3.5	0.5	0.1	-1.5	5.1	8.6	-3.3	5.5													
1978	-2.8	0.8	0.4	-0.9	4.6	7.1	-1.3	4.0	2.6												
1979	-4.1	-1.1	-1.6	-3.0	1.2	2.5	-5.0	-2.6	-6.7	-16.0											
1980	-4.3	-1.6	-2.1	-3.4	0.1	1.0	-5.3	-3.6	-6.6	-11.2	-6.4										
1981	-4.5	-2.0	-2.6	-3.8	-0.7	-0.1	-5.5	-4.2	-6.6	-9.6	-6.5	-6.6									
1982	-3.6	-1.3	-1.7	-2.7	0.2	0.9	-3.6	-2.2	-3.8	-5.4	-1.8	0.5	7.5								
1983	-0.9	1.5	1.3	0.7	3.6	4.6	1.1	2.9	2.5	2.5	7.1	11.6	20.7	34.0							
1984	-0.8	1.5	1.3	0.7	3.4	4.2	1.1	2.8	2.4	2.3	6.0	9.1	14.3	17.7	1.4						
1985	4.2	6.5	6.8	6.7	9.6	10.9	8.8	11.1	11.8	13.1	18.0	22.8	30.2	37.7	39.6	77.8					
1986	4.0	6.2	6.4	6.3	8.9	10.1	8.1	10.1	10.6	11.6	15.5	19.2	24.3	28.6	26.8	39.4	1.1				
1987	1.3	3.2	3.2	2.9	5.1	5.9	3.7	5.1	5.1	5.4	8.0	10.1	12.9	14.0	9.0	11.5	-21.7	-44.4			
1988	2.8	4.7	4.8	4.6	6.8	7.6	5.7	7.2	7.3	7.8	10.5	12.6	15.3	16.6	13.1	16.1	-4.5	-7.3	29.9		
1989	4.3	6.2	6.4	6.3	8.4	9.3	7.7	9.2	9.5	10.2	12.8	14.9	17.6	19.0	16.5	19.6	5.0	6.3	31.7	33.5	
1990	2.8	4.6	4.6	4.4	6.3	7.1	5.4	6.6	6.7	7.1	9.2	10.7	12.6	13.3	10.3	11.8	-1.4	-2.0	12.1	3.2	-27.1
1991	2.8	4.4	4.5	4.3	6.1	6.8	5.2	6.3	6.4	6.6	8.5	9.9	11.5	12.0	9.2	10.4	-0.9	-1.3	9.5	2.7	-12.7
1992	2.1	3.7	3.7	3.5	5.1	5.7	4.1	5.2	5.1	5.3	7.0	8.1	9.4	9.6	6.9	7.6	-2.5	-3.1	5.2	-1.0	-12.5
1993	3.7	5.2	5.3	5.2	6.8	7.5	6.1	7.2	7.3	7.6	9.3	10.5	11.9	12.3	10.1	11.1	2.7	3.0	10.9	7.1	0.5
1994	3.0	4.5	4.5	4.4	5.9	6.5	5.1	6.1	6.1	6.3	7.8	8.8	10.0	10.2	8.1	8.7	1.1	1.0	7.5	3.8	-2.1
1995	3.0	4.3	4.4	4.2	5.7	6.2	4.9	5.8	5.8	6.0	7.4	8.3	9.4	9.5	7.5	8.0	1.0	1.0	6.7	3.4	-1.6
1996	3.5	4.8	4.9	4.7	6.2	6.7	5.5	6.3	6.4	6.6	7.9	8.8	9.8	10.0	8.2	8.7	2.5	2.6	7.8	5.1	1.0
1997	4.8	6.1	6.2	6.2	7.6	8.1	7.0	8.0	8.1	8.4	9.7	10.7	11.7	12.0	10.5	11.2	5.6	6.0	11.1	9.0	5.9
1998	5.1	6.5	6.6	6.5	7.9	8.4	7.4	8.3	8.4	8.7	10.0	10.9	12.0	12.2	10.8	11.5	6.4	6.8	11.5	9.6	7.0
1999	6.2	7.5	7.7	7.6	9.0	9.6	8.6	9.5	9.7	10.1	11.4	12.3	13.3	13.7	12.4	13.2	8.5	9.1	13.6	12.1	10.0
2000	5.5	6.8	6.9	6.8	8.1	8.7	7.7	8.5	8.7	8.9	10.1	10.9	11.9	12.1	10.8	11.4	7.0	7.4	11.4	9.9	7.7
2001	4.6	5.8	5.9	5.8	7.0	7.5	6.5	7.3	7.4	7.6	8.6	9.4	10.1	10.3	9.0	9.4	5.1	5.4	9.0	7.4	5.2
2002	3.1	4.1	4.2	4.0	5.1	5.5	4.5	5.2	5.1	5.3	6.2	6.8	7.4	7.4	6.0	6.2	2.0	2.1	5.2	3.4	1.1
2003	3.9	5.0	5.1	5.0	6.1	6.5	5.5	6.2	6.2	6.4	7.3	7.9	8.5	8.6	7.3	7.6	3.7	3.9	6.9	5.4	3.4
2004	3.9	5.0	5.0	4.9	6.0	6.4	5.5	6.1	6.1	6.3	7.2	7.7	8.4	8.4	7.2	7.5	3.8	3.9	6.8	5.3	3.4
2005	4.5	5.5	5.6	5.5	6.6	7.0	6.1	6.7	6.8	6.9	7.8	8.4	9.0	9.1	7.9	8.2	4.8	5.0	7.7	6.4	4.7
2006	4.9	5.9	6.0	5.9	6.9	7.3	6.5	7.1	7.2	7.4	8.2	8.8	9.4	9.5	8.4	8.7	5.4	5.7	8.3	7.1	5.5
2007	5.2	6.2	6.3	6.3	7.3	7.7	6.9	7.5	7.6	7.7	8.6	9.1	9.7	9.8	8.8	9.2	6.0	6.3	8.8	7.7	6.3
2008	3.9	4.8	4.9	4.8	5.7	6.1	5.3	5.8	5.8	5.9	6.7	7.1	7.7	7.7	6.6	6.8	3.7	3.9	6.2	5.0	3.5
2009	4.3	5.2	5.3	5.2	6.1	6.4	5.7	6.2	6.2	6.4	7.1	7.6	8.1	8.1	7.1	7.3	4.4	4.5	6.8	5.7	4.3
2010	4.5	5.4	5.5	5.4	6.3	6.7	5.9	6.4	6.5	6.6	7.3	7.8	8.3	8.3	7.4	7.6	4.8	4.9	7.1	6.0	4.7

Germany Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
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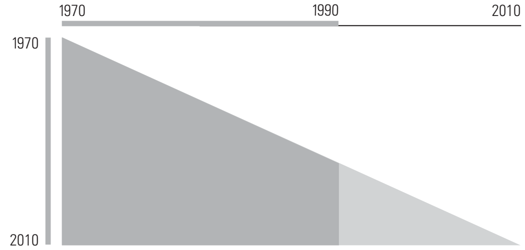
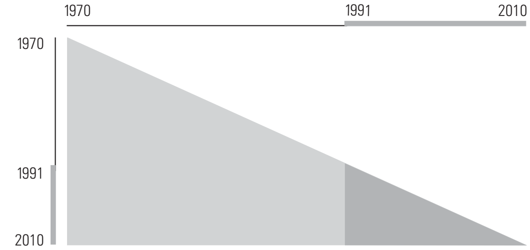
1989																				
1990																				
1991	1.7																			
1992	-5.1	-12.0																		
1993	9.7	13.6	39.3																	
1994	4.1	4.9	13.4	-12.5																
1995	3.5	3.9	9.2	-5.8	0.8															
1996	5.7	6.5	11.1	1.7	8.8	16.7														
1997	10.6	12.1	16.9	11.3	19.2	28.4	40.2													
1998	11.2	12.6	16.7	12.1	18.3	24.1	27.8	15.4												
1999	14.1	15.6	19.6	16.3	22.0	27.3	30.9	26.2	37.0											
2000	11.2	12.2	15.3	11.8	15.9	18.9	19.5	12.6	11.1	-14.8										
2001	8.1	8.8	11.1	7.5	10.4	12.0	11.0	3.8	-0.1	-18.7	-22.6									
2002	3.5	3.6	5.2	1.4	3.1	3.4	1.2	-6.6	-12.0	-28.4	-35.2	-47.8								
2003	5.7	6.1	7.7	4.5	6.4	7.1	5.8	0.0	-3.0	-13.1	-12.5	-7.4	32.9							
2004	5.6	5.9	7.4	4.5	6.2	6.8	5.6	0.6	-1.9	-9.6	-8.3	-3.6	18.5	4.1						
2005	6.8	7.2	8.7	6.1	7.8	8.5	7.6	3.5	1.8	-4.0	-1.9	3.3	20.3	14.0	23.9					
2006	7.6	8.0	9.4	7.1	8.7	9.4	8.7	5.2	3.9	-0.8	1.5	6.4	19.9	15.6	21.3	18.8				
2007	8.2	8.6	10.0	7.9	9.5	10.2	9.6	6.6	5.6	1.6	4.0	8.4	19.7	16.3	20.4	18.7	18.6			
2008	5.2	5.4	6.5	4.3	5.5	5.8	4.9	1.7	0.3	-3.7	-2.4	0.5	8.6	3.7	3.6	-3.2	-14.1	-46.8		
2009	5.9	6.2	7.2	5.2	6.4	6.8	6.0	3.2	2.1	-1.4	0.1	2.9	10.1	6.3	6.8	2.5	-2.9	-13.7	19.4	
2010	6.3	6.6	7.6	5.7	6.9	7.3	6.6	4.0	3.1	0.0	1.5	4.1	10.6	7.4	8.0	4.8	1.3	-4.4	16.8	14.1

Germany Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-31.8																				
1971	-8.1	15.6																			
1972	-1.9	13.1	10.6																		
1973	-5.1	3.8	-2.2	-15.0																	
1974	-2.9	4.4	0.6	-4.4	6.2																
1975	1.2	7.8	5.8	4.3	13.9	21.5															
1976	0.7	6.1	4.2	2.6	8.5	9.6	-2.2														
1977	2.9	7.9	6.6	5.7	10.9	12.5	8.0	18.2													
1978	4.7	9.2	8.3	7.9	12.5	14.1	11.6	18.5	18.8												
1979	3.1	7.0	5.9	5.2	8.6	9.0	5.9	8.6	3.8	-11.2											
1980	1.1	4.4	3.2	2.3	4.7	4.5	1.1	1.9	-3.5	-14.7	-18.2										
1981	-0.2	2.7	1.4	0.4	2.3	1.8	-1.5	-1.4	-6.3	-14.6	-16.4	-14.5									
1982	-0.1	2.6	1.4	0.5	2.2	1.7	-1.1	-0.9	-4.8	-10.7	-10.5	-6.6	1.2								
1983	1.2	3.7	2.7	2.0	3.7	3.4	1.2	1.6	-1.1	-5.1	-3.6	1.3	9.2	17.2							
1984	0.3	2.6	1.6	0.8	2.2	1.9	-0.3	-0.1	-2.7	-6.3	-5.3	-2.1	2.1	2.5	-12.2						
1985	8.2	10.9	10.6	10.6	12.7	13.3	12.5	14.1	13.6	12.8	16.8	23.8	33.4	44.1	57.6	127.5					
1986	9.4	12.0	11.7	11.8	13.9	14.5	13.9	15.5	15.2	14.7	18.4	24.5	32.3	40.1	47.8	77.8	28.1				
1987	7.1	9.4	9.0	8.9	10.6	10.9	10.1	11.2	10.5	9.6	12.2	16.5	21.7	25.7	27.9	41.3	-1.8	-31.8			
1988	7.6	9.8	9.4	9.3	10.9	11.3	10.5	11.6	11.0	10.2	12.5	16.4	20.8	24.1	25.4	34.9	4.0	-8.1	15.7		
1989	9.2	11.3	11.1	11.1	12.8	13.2	12.6	13.8	13.4	12.9	15.3	19.0	23.2	26.4	27.9	35.9	13.0	8.0	27.9	40.1	
1990	7.9	9.9	9.6	9.5	11.0	11.3	10.6	11.5	11.0	10.3	12.3	15.4	18.7	20.8	21.4	27.0	6.9	1.6	12.7	11.2	-17.7
1991	7.6	9.4	9.1	9.0	10.4	10.6	9.9	10.8	10.2	9.6	11.3	14.0	16.8	18.6	18.7	23.1	5.8	1.3	9.6	7.5	-8.7
1992	6.5	8.2	7.9	7.7	8.9	9.1	8.3	9.0	8.4	7.6	9.1	11.4	13.7	15.0	14.7	18.1	2.5	-1.8	4.2	1.3	-11.6
1993	7.4	9.2	8.9	8.8	10.0	10.2	9.5	10.2	9.7	9.1	10.6	12.8	15.1	16.3	16.2	19.4	5.9	2.7	8.5	7.0	-1.2
1994	7.1	8.7	8.4	8.3	9.4	9.6	8.9	9.5	9.0	8.4	9.7	11.7	13.8	14.8	14.6	17.3	5.0	2.1	7.0	5.5	-1.4
1995	7.2	8.7	8.4	8.3	9.4	9.5	8.9	9.5	9.1	8.5	9.7	11.6	13.4	14.4	14.1	16.5	5.4	2.9	7.3	6.1	0.4
1996	7.2	8.7	8.4	8.3	9.3	9.5	8.9	9.5	9.0	8.5	9.6	11.4	13.1	13.9	13.7	15.9	5.7	3.5	7.4	6.3	1.5
1997	7.7	9.1	8.9	8.8	9.8	10.0	9.4	10.0	9.6	9.1	10.2	11.9	13.5	14.4	14.2	16.2	6.9	5.0	8.7	7.9	3.9
1998	8.2	9.7	9.5	9.4	10.4	10.6	10.1	10.6	10.3	9.9	11.0	12.6	14.2	15.0	14.8	16.8	8.3	6.6	10.1	9.5	6.2
1999	8.5	9.9	9.7	9.7	10.6	10.8	10.4	10.9	10.6	10.2	11.3	12.8	14.3	15.1	15.0	16.8	8.9	7.4	10.7	10.2	7.2
2000	7.6	8.9	8.7	8.6	9.5	9.6	9.2	9.6	9.3	8.8	9.8	11.2	12.5	13.1	12.9	14.5	7.0	5.4	8.3	7.7	4.7
2001	6.5	7.8	7.5	7.4	8.2	8.3	7.8	8.2	7.8	7.3	8.1	9.4	10.6	11.1	10.7	12.1	4.9	3.3	5.8	5.1	2.1
2002	5.2	6.3	6.0	5.9	6.6	6.6	6.1	6.4	5.9	5.4	6.1	7.2	8.2	8.6	8.1	9.3	2.3	0.7	2.9	1.9	-1.0
2003	6.8	8.0	7.7	7.6	8.4	8.4	8.0	8.4	8.0	7.5	8.3	9.5	10.6	11.0	10.7	11.9	5.5	4.2	6.4	5.8	3.4
2004	6.9	8.1	7.8	7.8	8.5	8.6	8.1	8.5	8.1	7.7	8.5	9.6	10.6	11.1	10.8	11.9	5.9	4.6	6.8	6.2	3.9
2005	7.0	8.1	7.8	7.8	8.5	8.5	8.1	8.5	8.1	7.7	8.4	9.5	10.5	10.9	10.6	11.7	5.9	4.8	6.8	6.3	4.2
2006	7.7	8.7	8.6	8.5	9.2	9.3	8.9	9.3	9.0	8.6	9.3	10.4	11.4	11.8	11.6	12.7	7.2	6.2	8.2	7.7	5.8
2007	8.3	9.4	9.2	9.1	9.9	10.0	9.6	10.0	9.7	9.4	10.1	11.2	12.2	12.6	12.4	13.5	8.3	7.4	9.3	9.0	7.3
2008	6.8	7.8	7.6	7.5	8.2	8.2	7.8	8.1	7.8	7.4	8.1	9.0	9.9	10.2	9.9	10.9	5.8	4.8	6.5	6.1	4.3
2009	7.2	8.2	8.0	7.9	8.6	8.7	8.3	8.6	8.3	8.0	8.6	9.5	10.4	10.7	10.5	11.4	6.5	5.6	7.3	6.9	5.2
2010	7.2	8.2	8.0	7.9	8.5	8.6	8.2	8.5	8.2	7.9	8.5	9.4	10.2	10.6	10.3	11.2	6.5	5.6	7.3	6.9	5.3

Germany Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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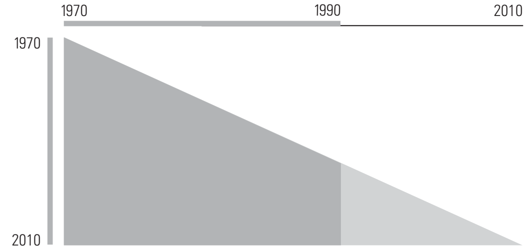
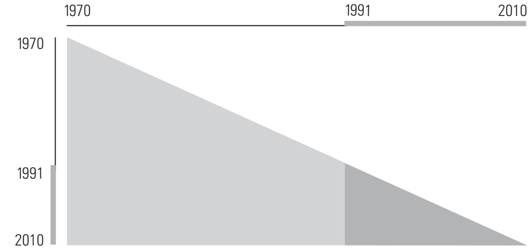
1991	0.2																			
1992	-8.5	-17.3																		
1993	4.2	6.3	29.8																	
1994	2.7	3.5	13.9	-1.9																
1995	4.0	5.0	12.4	3.6	9.2															
1996	4.7	5.6	11.4	5.2	8.8	8.4														
1997	6.9	8.1	13.1	9.0	12.6	14.3	20.1													
1998	9.1	10.4	15.0	12.1	15.6	17.7	22.4	24.6												
1999	10.0	11.2	15.3	12.9	15.9	17.5	20.6	20.8	17.0											
2000	7.0	7.7	10.9	8.2	9.9	10.0	10.4	7.1	-1.6	-20.2										
2001	3.9	4.3	6.7	3.8	4.7	3.9	3.0	-1.3	-9.9	-23.4	-26.6									
2002	0.4	0.4	2.2	-0.9	-0.7	-2.2	-3.9	-8.7	-17.1	-28.4	-32.5	-38.5								
2003	5.0	5.4	7.4	5.2	6.0	5.6	5.2	2.7	-1.7	-6.4	-1.8	10.6	59.8							
2004	5.5	5.9	7.8	5.8	6.6	6.3	6.1	4.0	0.6	-2.7	1.7	11.2	36.0	12.2						
2005	5.6	6.0	7.8	6.0	6.7	6.4	6.2	4.5	1.6	-1.0	2.9	10.2	26.5	9.9	7.5					
2006	7.3	7.8	9.6	8.0	8.9	8.8	8.9	7.6	5.5	3.9	7.9	14.8	28.1	17.5	20.1	32.8				
2007	8.7	9.3	11.0	9.7	10.6	10.7	10.9	10.0	8.4	7.3	11.2	17.5	28.8	21.0	23.9	32.1	31.5			
2008	5.5	5.8	7.3	5.8	6.3	6.1	5.9	4.6	2.6	1.0	3.7	8.0	15.7	6.9	5.6	4.9	-9.0	-49.4		
2009	6.4	6.8	8.2	6.9	7.4	7.3	7.2	6.2	4.5	3.2	5.8	9.9	16.8	9.6	9.1	9.5	1.8	-13.1	23.3	
2010	6.5	6.8	8.1	6.8	7.4	7.3	7.2	6.2	4.7	3.5	5.9	9.5	15.5	9.2	8.7	9.0	3.0	-6.5	15.0	6.7

Germany Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-33.0																				
1971	-14.0	4.9																			
1972	-5.4	8.3	11.7																		
1973	-11.5	-4.3	-9.0	-29.7																	
1974	-10.2	-4.6	-7.7	-17.4	-5.2																
1975	-2.4	3.7	3.4	0.6	15.8	36.7															
1976	-3.2	1.8	1.2	-1.5	7.9	14.5	-7.8														
1977	-1.8	2.7	2.3	0.4	7.9	12.3	0.0	7.8													
1978	-1.1	2.9	2.6	1.1	7.3	10.4	1.6	6.4	4.9												
1979	-2.4	1.0	0.5	-1.1	3.6	5.4	-2.5	-0.7	-5.0	-14.8											
1980	-2.9	0.1	-0.5	-2.0	2.0	3.2	-3.5	-2.5	-5.9	-11.3	-7.8										
1981	-3.4	-0.8	-1.3	-2.8	0.6	1.4	-4.5	-3.8	-6.7	-10.6	-8.5	-9.1									
1982	-2.6	-0.1	-0.5	-1.7	1.4	2.2	-2.8	-1.9	-3.9	-6.1	-3.2	-0.8	7.4								
1983	0.2	2.7	2.6	1.7	4.9	6.0	2.1	3.5	2.8	2.4	6.7	11.6	21.9	36.4							
1984	0.4	2.8	2.7	1.9	4.8	5.8	2.3	3.6	3.0	2.7	6.2	9.7	15.9	20.2	3.9						
1985	5.4	7.9	8.1	7.9	11.0	12.5	10.0	12.0	12.5	13.6	18.4	23.6	31.8	39.9	41.6	79.4					
1986	5.2	7.6	7.8	7.5	10.3	11.6	9.4	11.1	11.4	12.2	16.1	20.1	25.9	30.6	28.6	41.0	2.6				
1987	2.6	4.7	4.6	4.2	6.6	7.5	5.0	6.2	6.0	6.2	8.8	11.2	14.6	16.0	10.9	13.2	-19.9	-42.4			
1988	4.1	6.2	6.3	5.9	8.3	9.3	7.1	8.4	8.4	8.8	11.4	13.8	17.1	18.7	15.2	18.0	-2.5	-5.0	32.4		
1989	5.6	7.6	7.8	7.6	9.9	10.9	9.0	10.3	10.5	11.1	13.6	16.0	19.2	20.8	18.2	21.1	6.6	7.9	33.0	33.6	
1990	4.0	5.9	5.9	5.6	7.7	8.5	6.6	7.6	7.6	7.8	9.9	11.7	14.0	14.8	11.7	13.0	-0.3	-1.0	12.8	3.1	-27.5
1991	3.9	5.7	5.7	5.4	7.3	8.1	6.3	7.2	7.2	7.3	9.2	10.7	12.7	13.3	10.4	11.3	0.0	-0.5	9.9	2.4	-13.1
1992	3.1	4.8	4.8	4.4	6.2	6.8	5.1	5.9	5.8	5.8	7.4	8.7	10.3	10.6	7.7	8.2	-2.0	-2.8	5.2	-1.6	-13.4
1993	4.6	6.2	6.3	6.0	7.8	8.5	6.9	7.8	7.8	8.0	9.6	10.9	12.6	13.1	10.8	11.5	3.0	3.1	10.7	6.3	-0.5
1994	3.9	5.5	5.5	5.2	6.9	7.5	5.9	6.7	6.6	6.7	8.2	9.3	10.7	11.0	8.7	9.2	1.4	1.2	7.5	3.3	-2.8
1995	3.9	5.4	5.4	5.1	6.7	7.3	5.8	6.5	6.4	6.5	7.9	8.9	10.2	10.4	8.3	8.7	1.6	1.5	6.9	3.3	-1.7
1996	4.5	5.9	6.0	5.7	7.3	7.8	6.5	7.2	7.1	7.3	8.6	9.6	10.8	11.1	9.1	9.6	3.2	3.3	8.3	5.3	1.3
1997	5.9	7.3	7.4	7.2	8.7	9.3	8.1	8.9	8.9	9.1	10.5	11.5	12.8	13.2	11.5	12.1	6.5	6.9	11.8	9.5	6.5
1998	6.2	7.6	7.7	7.6	9.1	9.7	8.5	9.2	9.3	9.5	10.8	11.8	13.1	13.4	11.9	12.4	7.3	7.7	12.2	10.2	7.6
1999	7.3	8.7	8.8	8.7	10.2	10.8	9.7	10.5	10.6	10.9	12.2	13.2	14.5	14.9	13.5	14.2	9.5	10.0	14.4	12.8	10.7
2000	6.6	7.9	8.1	7.9	9.3	9.9	8.8	9.5	9.6	9.8	10.9	11.9	13.0	13.3	11.9	12.4	8.0	8.4	12.3	10.6	8.5
2001	5.7	7.0	7.0	6.9	8.2	8.7	7.6	8.2	8.2	8.4	9.4	10.2	11.2	11.4	10.0	10.4	6.1	6.3	9.8	8.1	5.9
2002	4.1	5.3	5.3	5.1	6.3	6.7	5.6	6.1	6.0	6.1	7.0	7.7	8.5	8.5	7.1	7.2	3.0	3.0	6.0	4.2	1.9
2003	5.0	6.2	6.2	6.1	7.2	7.7	6.6	7.2	7.1	7.2	8.2	8.8	9.7	9.8	8.4	8.7	4.7	4.9	7.8	6.2	4.2
2004	5.1	6.2	6.2	6.1	7.2	7.6	6.6	7.1	7.1	7.2	8.1	8.7	9.5	9.6	8.3	8.6	4.8	4.9	7.7	6.2	4.4
2005	5.6	6.7	6.8	6.6	7.8	8.2	7.2	7.8	7.8	7.9	8.7	9.4	10.2	10.3	9.1	9.3	5.8	6.0	8.7	7.3	5.7
2006	6.0	7.1	7.2	7.0	8.1	8.5	7.6	8.2	8.2	8.3	9.1	9.8	10.5	10.7	9.6	9.8	6.5	6.7	9.3	8.0	6.5
2007	6.3	7.4	7.5	7.4	8.4	8.9	8.0	8.5	8.5	8.6	9.5	10.1	10.9	11.0	9.9	10.2	7.1	7.3	9.7	8.6	7.2
2008	5.0	6.0	6.0	5.9	6.9	7.2	6.3	6.8	6.7	6.8	7.5	8.1	8.7	8.8	7.7	7.8	4.7	4.8	7.1	5.8	4.3
2009	5.4	6.4	6.4	6.3	7.3	7.6	6.8	7.2	7.2	7.3	8.0	8.6	9.2	9.3	8.2	8.4	5.4	5.6	7.7	6.6	5.2
2010	5.7	6.6	6.7	6.6	7.5	7.9	7.1	7.5	7.5	7.6	8.3	8.8	9.4	9.5	8.5	8.7	5.9	6.0	8.1	7.0	5.7

Germany Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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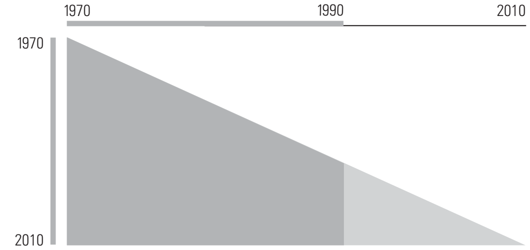
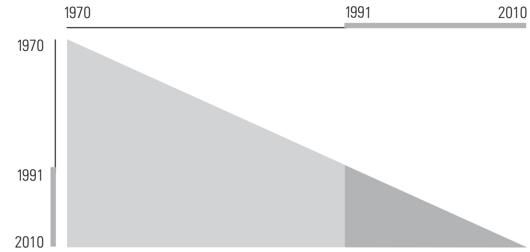
1991	1.2																			
1992	-6.3	-13.8																		
1993	8.5	12.2	38.2																	
1994	3.4	4.2	13.2	-11.8																
1995	3.4	4.0	9.9	-4.2	3.4															
1996	6.1	7.1	12.3	3.7	11.4	19.5														
1997	11.3	13.0	18.4	13.4	21.8	31.1	42.7													
1998	12.0	13.5	18.1	14.1	20.6	26.3	29.7	16.8												
1999	14.9	16.7	21.0	18.2	24.1	29.3	32.6	27.6	38.4											
2000	12.1	13.3	16.7	13.6	17.9	20.8	21.1	13.9	12.4	-13.6										
2001	9.0	9.7	12.4	9.1	12.1	13.6	12.4	4.8	0.8	-18.0	-22.4									
2002	4.3	4.6	6.5	3.0	4.8	5.0	2.6	-5.4	-11.0	-27.5	-34.4	-46.4								
2003	6.7	7.1	9.0	6.1	8.1	8.7	7.2	1.3	-1.9	-11.9	-11.4	-5.9	34.7							
2004	6.6	7.1	8.8	6.1	7.9	8.4	7.1	2.0	-0.5	-8.3	-7.0	-1.9	20.4	6.2						
2005	7.9	8.4	10.1	7.7	9.5	10.1	9.1	4.9	3.2	-2.7	-0.5	4.9	22.0	15.7	25.3					
2006	8.6	9.1	10.7	8.6	10.3	11.0	10.1	6.5	5.2	0.5	2.8	7.9	21.4	17.0	22.4	19.6				
2007	9.2	9.7	11.3	9.4	11.0	11.6	10.9	7.7	6.7	2.8	5.1	9.7	20.9	17.4	21.2	19.1	18.7			
2008	6.1	6.4	7.7	5.6	6.9	7.1	6.1	2.8	1.4	-2.7	-1.4	1.6	9.6	4.6	4.2	-2.8	-14.0	-46.7		
2009	6.9	7.2	8.5	6.6	7.9	8.2	7.3	4.4	3.2	-0.3	1.2	4.1	11.4	7.5	7.7	3.3	-2.1	-12.4	21.8	
2010	7.4	7.7	8.9	7.2	8.4	8.7	8.0	5.3	4.3	1.2	2.7	5.5	12.0	8.8	9.2	6.0	2.6	-2.8	19.2	16.5

Germany Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-34.2																				
1971	-14.2	5.8																			
1972	-5.5	8.9	12.1																		
1973	-12.9	-5.8	-11.5	-35.1																	
1974	-11.4	-5.7	-9.6	-20.4	-5.7																
1975	-3.9	2.1	1.2	-2.4	14.0	33.6															
1976	-4.6	0.3	-0.7	-3.9	6.4	12.5	-8.6														
1977	-2.9	1.5	0.8	-1.4	7.0	11.2	0.0	8.6													
1978	-1.9	2.1	1.6	-0.2	6.8	10.0	2.1	7.4	6.3												
1979	-3.3	0.2	-0.5	-2.3	3.1	4.9	-2.3	-0.2	-4.6	-15.5											
1980	-3.7	-0.6	-1.4	-3.0	1.5	2.8	-3.4	-2.1	-5.7	-11.7	-7.9										
1981	-3.7	-0.9	-1.6	-3.1	0.9	1.9	-3.4	-2.4	-5.2	-9.0	-5.7	-3.6									
1982	-2.9	-0.3	-0.9	-2.2	1.5	2.4	-2.0	-1.0	-2.9	-5.2	-1.7	1.4	6.3								
1983	-0.4	2.2	1.9	0.9	4.6	5.7	2.2	3.7	2.9	2.3	6.7	11.6	19.2	32.0							
1984	-0.2	2.3	2.0	1.2	4.5	5.5	2.3	3.7	3.0	2.5	6.1	9.5	13.9	17.7	3.4						
1985	6.2	8.9	9.1	8.9	12.6	14.2	12.3	14.6	15.3	16.6	22.0	28.0	35.8	45.7	52.5	101.6					
1986	6.0	8.5	8.7	8.5	11.8	13.3	11.4	13.4	14.0	14.9	19.3	23.8	29.3	35.1	36.1	52.4	3.2				
1987	2.7	4.9	4.9	4.4	7.2	8.2	6.1	7.4	7.3	7.4	10.3	12.9	15.6	17.5	13.8	17.3	-24.8	-52.9			
1988	4.1	6.3	6.3	5.9	8.7	9.7	7.9	9.2	9.3	9.6	12.4	14.9	17.6	19.5	16.9	20.3	-6.8	-11.7	29.4		
1989	5.7	7.8	7.9	7.7	10.3	11.4	9.8	11.2	11.5	11.9	14.7	17.2	19.8	21.7	20.0	23.3	3.7	3.9	32.3	35.2	
1990	3.9	5.9	5.9	5.5	7.9	8.8	7.1	8.2	8.2	8.3	10.5	12.3	14.1	15.1	12.7	14.2	-3.3	-4.9	11.1	2.0	-31.2
1991	3.8	5.6	5.6	5.3	7.5	8.3	6.7	7.7	7.7	7.8	9.7	11.3	12.8	13.5	11.2	12.3	-2.5	-3.7	8.6	1.7	-15.1
1992	3.1	4.8	4.7	4.4	6.5	7.1	5.6	6.5	6.3	6.3	8.0	9.3	10.5	10.9	8.6	9.2	-4.0	-5.2	4.4	-1.9	-14.3
1993	4.4	6.1	6.1	5.9	7.9	8.6	7.2	8.2	8.1	8.3	10.0	11.3	12.6	13.2	11.3	12.1	1.0	0.6	9.6	5.6	-1.8
1994	3.7	5.3	5.3	5.0	6.9	7.5	6.2	7.0	6.9	6.9	8.4	9.6	10.6	11.0	9.0	9.6	-0.6	-1.1	6.3	2.5	-4.1
1995	3.8	5.3	5.3	5.0	6.8	7.4	6.1	6.8	6.7	6.8	8.2	9.2	10.1	10.4	8.6	9.1	-0.1	-0.5	6.0	2.7	-2.7
1996	4.3	5.8	5.7	5.5	7.3	7.8	6.6	7.4	7.3	7.4	8.7	9.7	10.6	10.9	9.3	9.8	1.5	1.3	7.3	4.6	0.2
1997	5.4	6.9	6.9	6.7	8.5	9.1	8.0	8.8	8.8	8.9	10.3	11.3	12.3	12.7	11.3	11.9	4.4	4.5	10.3	8.1	4.7
1998	5.9	7.3	7.4	7.2	8.9	9.5	8.4	9.2	9.2	9.4	10.7	11.7	12.6	13.0	11.7	12.3	5.5	5.7	11.0	9.1	6.3
1999	6.7	8.2	8.2	8.1	9.8	10.4	9.4	10.2	10.3	10.4	11.7	12.8	13.7	14.1	13.0	13.6	7.4	7.7	12.7	11.2	8.8
2000	6.1	7.5	7.5	7.4	8.9	9.5	8.5	9.2	9.3	9.4	10.6	11.5	12.3	12.6	11.5	12.0	6.0	6.2	10.8	9.2	6.9
2001	5.3	6.5	6.6	6.4	7.9	8.4	7.4	8.0	8.0	8.1	9.2	10.0	10.6	10.9	9.7	10.1	4.3	4.4	8.5	6.9	4.5
2002	3.5	4.6	4.6	4.3	5.7	6.1	5.1	5.6	5.5	5.5	6.4	7.0	7.5	7.6	6.3	6.5	0.9	0.7	4.3	2.5	0.0
2003	4.6	5.8	5.8	5.6	6.9	7.4	6.4	7.0	6.9	6.9	7.9	8.5	9.1	9.2	8.1	8.3	3.2	3.2	6.7	5.1	3.0
2004	4.6	5.8	5.8	5.6	6.9	7.3	6.4	7.0	6.9	6.9	7.8	8.5	9.0	9.1	8.0	8.3	3.3	3.3	6.7	5.2	3.2
2005	5.1	6.2	6.2	6.1	7.4	7.8	6.9	7.5	7.4	7.5	8.3	9.0	9.5	9.6	8.6	8.9	4.2	4.3	7.5	6.2	4.4
2006	5.6	6.7	6.7	6.5	7.8	8.2	7.4	7.9	7.9	8.0	8.8	9.5	10.0	10.2	9.2	9.5	5.1	5.2	8.2	7.1	5.4
2007	6.0	7.1	7.1	7.0	8.2	8.6	7.8	8.4	8.4	8.4	9.3	9.9	10.4	10.6	9.7	10.0	5.8	5.9	8.9	7.8	6.3
2008	4.7	5.7	5.7	5.5	6.7	7.0	6.2	6.7	6.6	6.6	7.4	8.0	8.4	8.5	7.5	7.7	3.6	3.6	6.3	5.2	3.6
2009	5.1	6.1	6.2	6.0	7.1	7.5	6.7	7.2	7.2	7.2	7.9	8.5	8.9	9.0	8.1	8.3	4.4	4.5	7.1	6.0	4.6
2010	5.4	6.4	6.4	6.2	7.4	7.7	7.0	7.4	7.4	7.4	8.2	8.7	9.1	9.2	8.4	8.6	4.9	4.9	7.5	6.5	5.1

Germany Short-Horizon Equity Risk Premia (in U.S. Dollars)



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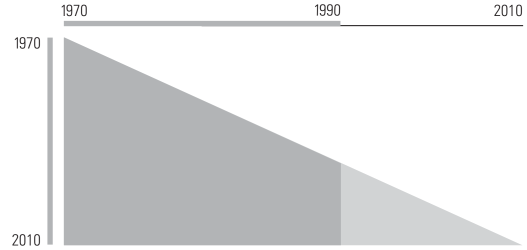
1990																				
1991	1.1																			
1992	-5.8	-12.6																		
1993	8.0	11.5	35.6																	
1994	2.7	3.2	11.2	-13.2																
1995	3.0	3.4	8.8	-4.6	4.1															
1996	5.4	6.3	11.0	2.8	10.9	17.7														
1997	9.9	11.3	16.1	11.3	19.5	27.2	36.6													
1998	10.9	12.3	16.5	12.7	19.2	24.2	27.5	18.3												
1999	13.3	14.8	18.7	15.9	21.7	26.1	29.0	25.1	31.9											
2000	10.7	11.7	14.8	11.8	16.0	18.4	18.5	12.5	9.6	-12.7										
2001	7.8	8.5	10.8	7.7	10.7	11.8	10.6	4.1	-0.6	-16.8	-21.0									
2002	2.6	2.7	4.3	0.8	2.5	2.3	-0.2	-7.6	-14.1	-29.4	-37.8	-54.6								
2003	5.6	6.0	7.7	4.9	6.9	7.3	5.8	0.7	-2.9	-11.6	-11.2	-6.3	42.1							
2004	5.7	6.1	7.6	5.1	6.9	7.2	5.9	1.5	-1.3	-7.9	-6.7	-2.0	24.3	6.6						
2005	6.7	7.2	8.7	6.4	8.2	8.6	7.6	4.0	2.0	-3.0	-1.1	3.9	23.4	14.0	21.4					
2006	7.7	8.2	9.6	7.6	9.4	9.9	9.1	6.0	4.5	0.6	2.8	7.5	23.1	16.7	21.8	22.2				
2007	8.5	9.0	10.4	8.6	10.3	10.8	10.2	7.5	6.3	3.1	5.4	9.8	22.7	17.8	21.5	21.6	21.0			
2008	5.5	5.8	6.9	5.0	6.3	6.5	5.6	2.7	1.2	-2.2	-0.9	1.9	11.4	5.2	4.9	-0.6	-12.0	-45.0		
2009	6.5	6.8	7.9	6.2	7.5	7.7	6.9	4.5	3.2	0.3	1.8	4.6	13.1	8.2	8.6	5.4	-0.3	-10.9	23.2	
2010	6.9	7.2	8.3	6.7	8.0	8.2	7.5	5.3	4.2	1.7	3.1	5.8	13.4	9.3	9.7	7.4	3.7	-2.1	19.4	15.6

Ireland Long-Horizon Equity Risk Premia (in Local Currency)



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1973	NA	NA	NA	NA																	
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1981	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
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1988	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	28.3		
1989	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	28.2	28.1	
1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.6	-4.3	-36.7
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.1	-1.3	-16.0
1992	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0	-7.1	-18.8
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1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.8	4.9	1.0
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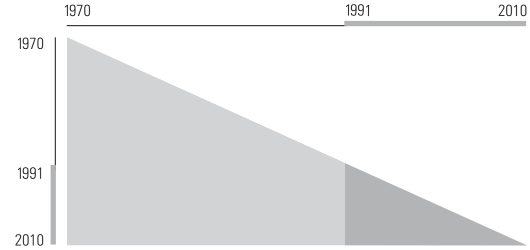
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.3	7.7	5.9
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.5	6.9	5.2
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.1	3.4	1.5
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.7	4.2	2.5
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.1	5.7	4.2
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.2	5.9	4.6
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.3	7.2	6.0
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.3	5.2	3.9
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.4	1.2	-0.3
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.5	1.3	0.0
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.7	0.5	-0.8

Ireland Long-Horizon Equity Risk Premia (in Local Currency)



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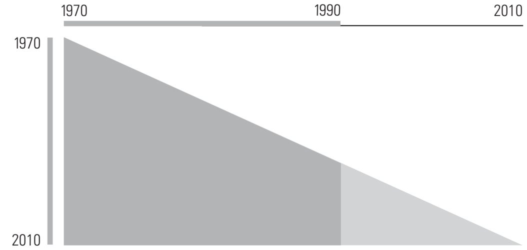
1991	4.8																			
1992	-9.8	-24.4																		
1993	11.9	15.5	55.3																	
1994	8.3	9.5	26.4	-2.5																
1995	8.5	9.5	20.8	3.5	9.5															
1996	10.0	11.1	20.0	8.2	13.6	17.6														
1997	13.1	14.4	22.2	13.9	19.4	24.4	31.1													
1998	14.4	15.8	22.5	16.0	20.6	24.3	27.6	24.2												
1999	12.6	13.6	19.0	13.0	16.1	17.7	17.7	11.1	-2.0											
2000	10.1	10.7	15.1	9.4	11.3	11.7	10.2	3.3	-7.2	-12.3										
2001	9.0	9.4	13.2	7.9	9.4	9.4	7.7	1.8	-5.6	-7.4	-2.5									
2002	4.7	4.7	7.6	2.3	2.9	2.0	-0.7	-7.0	-14.8	-19.1	-22.4	-42.4								
2003	5.5	5.6	8.3	3.6	4.3	3.6	1.6	-3.3	-8.8	-10.4	-9.8	-13.5	15.4							
2004	7.2	7.4	10.0	5.9	6.7	6.4	5.0	1.3	-2.5	-2.6	-0.2	0.5	22.0	28.6						
2005	7.3	7.5	9.9	6.2	7.0	6.7	5.5	2.3	-0.8	-0.6	1.7	2.7	17.8	19.0	9.4					
2006	8.6	8.9	11.3	7.9	8.7	8.7	7.8	5.2	2.8	3.5	6.1	7.9	20.4	22.1	18.9	28.4				
2007	6.3	6.4	8.4	5.1	5.6	5.3	4.2	1.5	-1.0	-0.9	0.8	1.3	10.0	8.7	2.1	-1.6	-31.6			
2008	1.8	1.6	3.2	-0.3	-0.1	-0.8	-2.4	-5.4	-8.4	-9.1	-8.7	-9.6	-4.1	-8.0	-17.1	-26.0	-53.2	-74.7		
2009	1.9	1.7	3.3	0.0	0.2	-0.5	-1.9	-4.6	-7.2	-7.7	-7.2	-7.8	-2.9	-5.9	-12.8	-18.4	-34.0	-35.2	4.4	
2010	1.0	0.8	2.1	-1.0	-0.9	-1.6	-2.9	-5.6	-8.0	-8.6	-8.2	-8.9	-4.7	-7.5	-13.5	-18.1	-29.8	-29.2	-6.4	-17.2

Ireland Long-Horizon Equity Risk Premia (in U.S. Dollars)



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1981	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
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1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
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1988	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	16.0		
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1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.9	2.4	-27.7
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.9	2.5	-12.4
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1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.2	7.2	3.6
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1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.1	7.4	4.9
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.1	5.3	2.8
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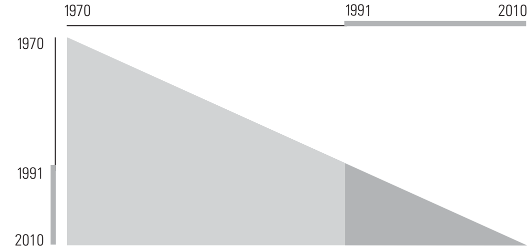
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.6	1.7	-0.7
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	4.9	4.2	2.1
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.9	6.3	4.6
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.2	5.6	4.0
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.2	7.7	6.3
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.6	6.1	4.6
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.6	2.0	0.4
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.9	2.2	0.7
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.8	1.1	-0.4

Ireland Long-Horizon Equity Risk Premia (in U.S. Dollars)



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1970																				
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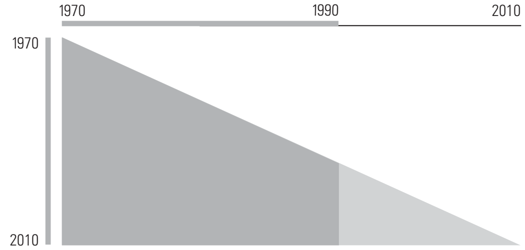
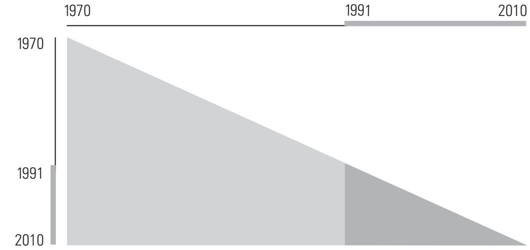
1990																				
1991	2.8																			
1992	-13.4	-29.6																		
1993	2.6	2.6	34.8																	
1994	3.7	4.0	20.8	6.8																
1995	5.7	6.4	18.4	10.2	13.6															
1996	8.8	10.0	19.9	14.9	19.0	24.4														
1997	9.0	10.0	18.0	13.8	16.1	17.3	10.3													
1998	11.6	12.8	19.9	16.9	19.4	21.4	19.9	29.5												
1999	8.5	9.2	14.7	11.4	12.3	12.0	7.8	6.6	-16.3											
2000	5.9	6.2	10.7	7.2	7.3	6.0	1.4	-1.5	-17.0	-17.7										
2001	4.6	4.8	8.7	5.4	5.2	3.8	-0.3	-3.0	-13.8	-12.6	-7.5									
2002	1.6	1.5	4.6	1.2	0.5	-1.3	-5.6	-8.8	-18.4	-19.1	-19.8	-32.1								
2003	4.4	4.6	7.7	5.0	4.8	3.7	0.7	-0.9	-7.0	-4.6	-0.3	3.3	38.7							
2004	6.9	7.2	10.3	8.0	8.1	7.5	5.4	4.7	0.6	4.0	9.4	15.1	38.6	38.5						
2005	6.1	6.3	9.1	6.9	6.9	6.3	4.3	3.5	-0.2	2.5	6.5	10.0	24.1	16.7	-5.1					
2006	8.4	8.8	11.5	9.7	10.0	9.7	8.2	8.0	5.3	8.3	12.7	16.7	28.9	25.7	19.2	43.5				
2007	6.5	6.7	9.2	7.3	7.4	6.8	5.3	4.7	2.0	4.3	7.4	9.9	18.3	13.2	4.8	9.7	-24.1			
2008	1.9	1.9	3.8	1.8	1.4	0.5	-1.5	-2.6	-5.8	-4.6	-3.0	-2.4	2.6	-4.6	-15.4	-18.9	-50.1	-76.0		
2009	2.2	2.2	4.1	2.1	1.8	1.0	-0.8	-1.7	-4.6	-3.4	-1.8	-1.1	3.3	-2.6	-10.8	-12.2	-30.8	-34.1	7.8	
2010	1.0	0.9	2.6	0.7	0.3	-0.6	-2.4	-3.3	-6.1	-5.1	-3.9	-3.5	0.1	-5.4	-12.7	-14.3	-28.7	-30.2	-7.4	-22.5

Italy Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-24.9																				
1971	-24.8	-24.7																			
1972	-14.8	-9.8	5.1																		
1973	-8.8	-3.4	7.2	9.3																	
1974	-14.5	-11.9	-7.6	-13.9	-37.1																
1975	-14.6	-12.5	-9.5	-14.4	-26.2	-15.3															
1976	-15.0	-13.3	-11.0	-15.1	-23.2	-16.2	-17.1														
1977	-17.1	-16.0	-14.6	-18.5	-25.5	-21.6	-24.7	-32.3													
1978	-12.4	-10.8	-8.8	-11.1	-15.2	-9.7	-7.9	-3.2	25.9												
1979	-11.0	-9.5	-7.6	-9.4	-12.5	-7.6	-5.7	-1.8	13.4	0.9											
1980	-1.4	0.9	3.8	3.6	2.8	9.5	14.4	22.3	40.6	47.9	94.9										
1981	-1.3	0.8	3.4	3.2	2.4	8.1	12.0	17.8	30.4	31.8	47.3	-0.3									
1982	-3.4	-1.6	0.5	0.0	-1.0	3.5	6.2	10.1	18.6	16.7	22.0	-14.4	-28.6								
1983	-2.7	-1.0	1.0	0.6	-0.3	3.8	6.2	9.5	16.5	14.6	18.1	-7.6	-11.2	6.2							
1984	-1.9	-0.2	1.7	1.4	0.6	4.4	6.6	9.6	15.6	13.9	16.4	-3.2	-4.1	8.1	9.9						
1985	3.8	5.7	7.9	8.1	8.0	12.1	14.8	18.4	24.7	24.6	28.5	15.2	19.1	35.0	49.4	88.9					
1986	6.8	8.8	11.0	11.5	11.6	15.7	18.5	22.1	28.1	28.4	32.3	21.9	26.3	40.0	51.3	72.0	55.0				
1987	4.1	5.8	7.7	7.9	7.8	11.3	13.5	16.3	21.1	20.6	23.1	12.8	15.0	23.7	28.1	34.1	6.7	-41.7			
1988	4.7	6.4	8.2	8.4	8.3	11.6	13.6	16.2	20.6	20.1	22.2	13.1	15.0	22.3	25.5	29.4	9.6	-13.2	15.3		
1989	4.7	6.3	8.0	8.2	8.1	11.1	13.0	15.3	19.3	18.7	20.5	12.2	13.8	19.9	22.1	24.6	8.5	-7.0	10.3	5.2	
1990	2.6	3.9	5.4	5.5	5.2	7.9	9.4	11.3	14.7	13.7	14.9	6.9	7.7	12.2	13.1	13.6	-1.4	-15.5	-6.8	-17.9	-41.1
1991	1.9	3.2	4.5	4.5	4.3	6.7	8.1	9.7	12.7	11.7	12.6	5.2	5.7	9.5	9.9	9.9	-3.2	-14.9	-8.2	-16.1	-26.7
1992	1.3	2.5	3.8	3.7	3.4	5.6	6.9	8.4	11.1	10.0	10.7	3.7	4.1	7.3	7.5	7.2	-4.5	-14.4	-9.0	-15.1	-21.8
1993	2.7	3.9	5.3	5.3	5.1	7.3	8.5	10.0	12.7	11.8	12.6	6.3	6.8	10.0	10.4	10.4	0.6	-7.1	-1.4	-4.7	-7.2
1994	2.5	3.7	4.9	4.9	4.7	6.8	7.9	9.3	11.8	10.9	11.6	5.6	6.1	8.9	9.2	9.1	0.3	-6.6	-1.6	-4.4	-6.3
1995	1.9	3.0	4.2	4.1	3.9	5.8	6.9	8.2	10.4	9.5	10.0	4.4	4.7	7.3	7.4	7.1	-1.0	-7.3	-3.0	-5.6	-7.4
1996	1.8	2.8	3.9	3.9	3.6	5.5	6.5	7.6	9.8	8.9	9.3	4.0	4.3	6.6	6.6	6.4	-1.1	-6.8	-2.9	-5.2	-6.7
1997	3.5	4.6	5.7	5.8	5.6	7.5	8.5	9.7	11.8	11.1	11.6	6.7	7.2	9.6	9.8	9.8	3.2	-1.5	2.5	1.1	0.6
1998	4.7	5.8	6.9	7.0	6.9	8.7	9.8	11.0	13.0	12.4	13.0	8.5	9.0	11.3	11.7	11.8	5.8	1.7	5.7	4.7	4.7
1999	5.0	6.0	7.1	7.2	7.1	8.9	9.9	11.1	13.0	12.4	13.0	8.7	9.2	11.4	11.7	11.9	6.4	2.6	6.3	5.5	5.5
2000	4.8	5.8	6.9	7.0	6.9	8.6	9.5	10.6	12.5	11.9	12.4	8.3	8.7	10.8	11.1	11.2	6.0	2.5	5.9	5.1	5.1
2001	3.8	4.8	5.8	5.8	5.7	7.2	8.1	9.1	10.8	10.2	10.6	6.6	6.9	8.8	8.9	8.9	3.9	0.5	3.5	2.6	2.4
2002	3.0	3.8	4.7	4.7	4.6	6.1	6.9	7.8	9.4	8.7	9.0	5.1	5.4	7.1	7.1	7.0	2.2	-1.1	1.6	0.6	0.2
2003	3.2	4.0	4.9	4.9	4.8	6.2	7.0	7.9	9.5	8.8	9.1	5.4	5.7	7.3	7.3	7.2	2.7	-0.4	2.2	1.3	1.0
2004	3.7	4.5	5.4	5.4	5.3	6.7	7.5	8.3	9.8	9.2	9.6	6.0	6.3	7.9	7.9	7.8	3.6	0.7	3.2	2.4	2.3
2005	4.0	4.8	5.7	5.7	5.6	7.0	7.7	8.6	10.0	9.4	9.8	6.4	6.6	8.2	8.3	8.2	4.1	1.5	3.9	3.2	3.1
2006	4.3	5.1	6.0	6.0	5.9	7.3	8.0	8.8	10.2	9.7	10.0	6.7	7.0	8.5	8.6	8.5	4.7	2.2	4.5	3.9	3.8
2007	4.0	4.8	5.6	5.6	5.5	6.8	7.5	8.3	9.6	9.1	9.4	6.2	6.5	7.9	7.9	7.8	4.2	1.7	3.9	3.3	3.2
2008	2.6	3.3	4.1	4.0	3.9	5.1	5.7	6.4	7.7	7.1	7.3	4.2	4.3	5.6	5.6	5.4	1.8	-0.7	1.3	0.6	0.3
2009	3.0	3.7	4.5	4.5	4.3	5.5	6.1	6.8	8.1	7.5	7.7	4.7	4.9	6.1	6.1	6.0	2.5	0.2	2.1	1.5	1.3
2010	2.7	3.3	4.1	4.0	3.9	5.0	5.6	6.3	7.4	6.9	7.1	4.1	4.3	5.5	5.4	5.3	1.9	-0.3	1.5	0.9	0.7

Italy Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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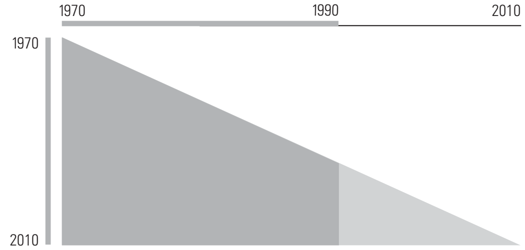
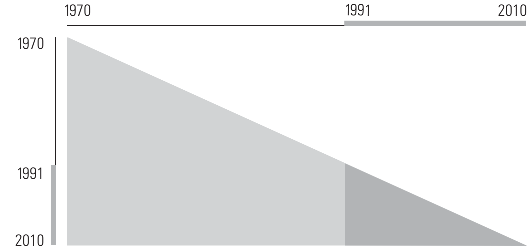
1990																				
1991	-12.3																			
1992	-12.2	-12.1																		
1993	4.1	12.3	36.7																	
1994	2.4	7.2	16.9	-2.9																
1995	-0.7	2.2	7.0	-7.8	-12.8															
1996	-0.9	1.4	4.7	-5.9	-7.5	-2.1														
1997	6.5	9.7	14.0	8.4	12.1	24.5	51.2													
1998	10.4	13.6	17.9	14.2	18.4	28.8	44.3	37.4												
1999	10.7	13.6	17.2	14.0	17.4	24.9	33.9	25.3	13.1											
2000	9.7	12.1	15.1	12.1	14.6	20.0	25.6	17.0	6.8	0.4										
2001	6.3	8.2	10.4	7.1	8.6	12.1	15.0	5.9	-4.6	-13.4	-27.3									
2002	3.7	5.1	6.8	3.5	4.3	6.7	8.2	-0.4	-9.8	-17.5	-26.5	-25.6								
2003	4.2	5.6	7.2	4.3	5.1	7.3	8.6	1.5	-5.6	-10.3	-13.9	-7.2	11.2							
2004	5.4	6.7	8.3	5.7	6.6	8.7	10.1	4.2	-1.4	-4.3	-5.4	1.8	15.6	19.9						
2005	6.0	7.3	8.8	6.5	7.3	9.3	10.6	5.5	1.0	-1.0	-1.3	5.2	15.4	17.5	15.1					
2006	6.6	7.9	9.3	7.2	8.1	10.0	11.2	6.7	2.9	1.4	1.6	7.4	15.6	17.1	15.6	16.2				
2007	5.8	6.9	8.2	6.2	6.9	8.5	9.5	5.3	1.7	0.3	0.3	4.9	11.0	10.9	7.9	4.3	-7.5			
2008	2.6	3.5	4.5	2.4	2.7	3.9	4.4	0.2	-3.6	-5.4	-6.1	-3.1	0.6	-1.5	-6.8	-14.2	-29.3	-51.2		
2009	3.5	4.4	5.4	3.4	3.8	5.0	5.6	1.8	-1.5	-2.9	-3.3	-0.3	3.3	2.0	-1.6	-5.7	-13.0	-15.8	19.6	
2010	2.8	3.5	4.4	2.5	2.9	3.9	4.3	0.7	-2.3	-3.7	-4.2	-1.6	1.4	0.0	-3.3	-7.0	-12.8	-14.6	3.8	-12.1

Italy Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-24.9																				
1971	-22.9	-20.8																			
1972	-12.8	-6.8	7.2																		
1973	-8.8	-3.4	5.3	3.4																	
1974	-15.1	-12.6	-9.9	-18.5	-40.4																
1975	-15.8	-14.0	-12.3	-18.8	-30.0	-19.5															
1976	-18.6	-17.6	-16.9	-22.9	-31.7	-27.4	-35.3														
1977	-20.3	-19.6	-19.4	-24.8	-31.8	-28.9	-33.6	-32.0													
1978	-14.4	-13.1	-12.0	-15.3	-19.0	-13.6	-11.7	0.1	32.3												
1979	-12.6	-11.2	-10.0	-12.5	-15.1	-10.1	-7.7	1.4	18.2	4.1											
1980	-5.2	-3.3	-1.3	-2.4	-3.2	3.0	7.5	18.2	34.9	36.2	68.4										
1981	-6.7	-5.0	-3.5	-4.6	-5.6	-0.7	2.5	10.0	20.5	16.6	22.9	-22.7									
1982	-9.0	-7.7	-6.5	-7.9	-9.2	-5.3	-3.2	2.1	8.9	3.1	2.8	-30.0	-37.4								
1983	-9.3	-8.1	-7.0	-8.3	-9.5	-6.0	-4.4	0.1	5.4	0.0	-1.0	-24.1	-24.8	-12.2							
1984	-9.0	-7.9	-6.9	-8.1	-9.1	-6.0	-4.5	-0.7	3.8	-0.9	-1.9	-19.5	-18.4	-9.0	-5.7						
1985	-1.2	0.4	2.0	1.5	1.4	5.2	7.7	12.4	18.0	15.9	17.9	7.8	15.5	33.1	55.7	117.1					
1986	4.4	6.2	8.0	8.1	8.4	12.5	15.4	20.5	26.3	25.6	28.6	22.0	30.9	48.0	68.1	105.0	92.9				
1987	2.3	3.9	5.5	5.4	5.5	9.0	11.4	15.6	20.4	19.1	21.0	14.2	20.4	31.9	42.9	59.1	30.1	-32.6			
1988	2.4	3.9	5.3	5.2	5.3	8.6	10.8	14.6	18.8	17.5	19.0	12.8	17.9	27.1	34.9	45.1	21.1	-14.8	3.0		
1989	2.7	4.1	5.5	5.4	5.5	8.6	10.6	14.1	18.0	16.7	17.9	12.3	16.7	24.4	30.6	37.8	18.0	-7.0	5.8	8.6	
1990	0.9	2.2	3.4	3.2	3.2	5.9	7.6	10.7	14.0	12.5	13.2	7.7	11.1	17.1	21.3	25.9	7.6	-13.7	-7.4	-12.6	-33.9
1991	0.2	1.4	2.6	2.3	2.3	4.8	6.3	9.0	12.0	10.4	11.0	5.7	8.6	13.7	16.9	20.1	4.0	-13.8	-9.1	-13.1	-24.0
1992	-1.1	0.0	0.9	0.6	0.5	2.8	4.1	6.5	9.1	7.4	7.7	2.6	4.9	9.2	11.5	13.7	-1.1	-16.7	-13.6	-17.7	-26.5
1993	-0.3	0.7	1.7	1.5	1.4	3.6	4.8	7.2	9.6	8.1	8.4	3.8	6.0	10.0	12.2	14.2	1.3	-11.8	-8.3	-10.6	-15.4
1994	-0.2	0.8	1.8	1.5	1.4	3.5	4.7	6.9	9.2	7.8	8.0	3.7	5.8	9.3	11.3	13.0	1.4	-10.0	-6.8	-8.4	-11.8
1995	-0.6	0.3	1.2	1.0	0.9	2.8	3.9	6.0	8.1	6.7	6.9	2.8	4.6	7.8	9.5	10.8	0.2	-10.1	-7.3	-8.7	-11.6
1996	-0.5	0.4	1.3	1.0	0.9	2.8	3.8	5.8	7.8	6.4	6.6	2.7	4.4	7.4	8.9	10.1	0.4	-8.9	-6.2	-7.4	-9.7
1997	0.6	1.5	2.4	2.2	2.1	4.0	5.0	7.0	8.9	7.7	7.9	4.3	6.0	8.9	10.4	11.6	2.9	-5.3	-2.6	-3.2	-4.7
1998	2.2	3.1	4.0	3.9	3.9	5.8	6.9	8.8	10.7	9.6	9.9	6.7	8.4	11.3	12.8	14.2	6.2	-1.0	1.9	1.8	1.0
1999	2.0	2.9	3.8	3.6	3.6	5.4	6.4	8.2	10.1	9.0	9.3	6.2	7.8	10.4	11.8	13.0	5.6	-1.2	1.5	1.3	0.6
2000	1.7	2.6	3.4	3.3	3.3	5.0	5.9	7.7	9.4	8.4	8.6	5.6	7.1	9.5	10.8	11.8	4.8	-1.5	0.9	0.7	0.0
2001	0.7	1.5	2.3	2.1	2.1	3.6	4.5	6.1	7.7	6.6	6.8	3.8	5.1	7.4	8.5	9.3	2.6	-3.5	-1.4	-1.7	-2.6
2002	0.3	1.1	1.8	1.6	1.6	3.1	3.9	5.4	6.9	5.8	5.9	3.1	4.3	6.4	7.4	8.1	1.7	-4.0	-2.1	-2.5	-3.3
2003	1.3	2.1	2.8	2.7	2.6	4.1	5.0	6.5	7.9	7.0	7.1	4.4	5.6	7.7	8.7	9.5	3.5	-1.8	0.1	-0.1	-0.7
2004	2.1	2.9	3.6	3.5	3.5	5.0	5.8	7.3	8.7	7.8	8.0	5.5	6.7	8.7	9.7	10.4	4.8	-0.1	1.8	1.8	1.3
2005	2.0	2.8	3.5	3.4	3.4	4.8	5.6	7.0	8.4	7.5	7.7	5.2	6.4	8.3	9.2	9.9	4.6	-0.1	1.7	1.7	1.2
2006	2.8	3.6	4.2	4.2	4.2	5.6	6.4	7.8	9.1	8.3	8.5	6.2	7.3	9.2	10.1	10.8	5.8	1.4	3.2	3.2	2.9
2007	2.8	3.5	4.2	4.1	4.1	5.5	6.3	7.6	8.9	8.1	8.3	6.0	7.1	8.9	9.8	10.5	5.6	1.5	3.2	3.2	2.9
2008	1.3	2.0	2.6	2.5	2.5	3.8	4.5	5.7	6.9	6.1	6.1	3.9	4.9	6.5	7.3	7.8	3.1	-1.0	0.5	0.4	-0.1
2009	1.9	2.6	3.2	3.1	3.1	4.3	5.0	6.2	7.4	6.6	6.7	4.6	5.6	7.2	7.9	8.4	3.9	0.0	1.5	1.5	1.1
2010	1.4	2.1	2.7	2.5	2.5	3.7	4.4	5.5	6.7	5.9	5.9	3.8	4.8	6.3	6.9	7.4	3.0	-0.7	0.7	0.6	0.2

Italy Long-Horizon Equity Risk Premia (in U.S. Dollars)



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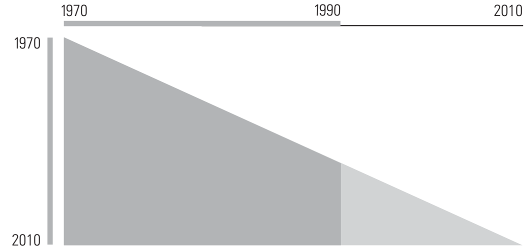
1991	-14.1																			
1992	-22.7	-31.4																		
1993	-9.2	-6.7	18.0																	
1994	-6.3	-3.6	10.2	2.5																
1995	-7.2	-5.4	3.2	-4.1	-10.8															
1996	-5.6	-3.9	2.9	-2.1	-4.4	2.1														
1997	-0.5	1.7	8.4	6.0	7.1	16.1	30.1													
1998	5.4	8.2	14.8	14.2	17.1	26.3	38.5	46.9												
1999	4.4	6.7	12.2	11.2	13.0	18.9	24.5	21.8	-3.4											
2000	3.4	5.4	10.0	8.8	9.9	14.0	17.0	12.6	-4.5	-5.7										
2001	0.3	1.7	5.4	3.8	4.0	6.5	7.4	1.7	-13.4	-18.4	-31.1									
2002	-0.8	0.4	3.6	2.0	2.0	3.8	4.1	-1.1	-13.1	-16.4	-21.7	-12.3								
2003	1.9	3.2	6.4	5.2	5.5	7.5	8.3	4.7	-3.8	-3.8	-3.2	10.7	33.7							
2004	3.8	5.2	8.3	7.4	7.9	9.9	10.9	8.2	1.7	2.8	4.9	16.9	31.4	29.2						
2005	3.6	4.8	7.6	6.8	7.1	8.9	9.7	7.2	1.5	2.3	3.9	12.6	20.9	14.6	-0.1					
2006	5.2	6.5	9.2	8.5	9.0	10.8	11.7	9.7	5.0	6.2	8.2	16.1	23.2	19.7	14.9	29.9				
2007	5.1	6.3	8.8	8.1	8.5	10.2	10.9	9.0	4.8	5.8	7.4	13.8	19.0	15.4	10.8	16.2	2.6			
2008	1.8	2.7	4.9	4.0	4.1	5.2	5.5	3.3	-1.1	-0.8	-0.2	4.2	6.9	1.6	-5.3	-7.0	-25.5	-53.6		
2009	2.9	3.9	6.0	5.2	5.4	6.6	6.9	5.0	1.2	1.6	2.4	6.6	9.3	5.2	0.4	0.6	-9.2	-15.1	23.5	
2010	1.9	2.7	4.6	3.9	3.9	4.9	5.1	3.2	-0.4	-0.2	0.4	3.9	5.9	1.9	-2.6	-3.1	-11.3	-16.0	2.8	-17.8

Italy Short-Horizon Equity Risk Premia (in Local Currency)



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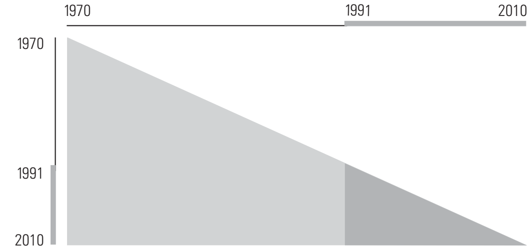
1981	NA	NA	NA	NA	NA	NA	NA	NA	28.3	28.9	43.0	-5.6									
1982	NA	NA	NA	NA	NA	NA	NA	NA	16.8	14.4	18.9	-17.4	-29.3								
1983	NA	NA	NA	NA	NA	NA	NA	NA	15.0	12.7	15.6	-9.7	-11.7	5.8							
1984	NA	NA	NA	NA	NA	NA	NA	NA	14.3	12.3	14.6	-4.6	-4.3	8.1	10.5						
1985	NA	NA	NA	NA	NA	NA	NA	NA	23.6	23.2	26.9	14.0	18.8	34.9	49.4	88.4					
1986	NA	NA	NA	NA	NA	NA	NA	NA	27.2	27.3	31.0	21.0	26.3	40.2	51.6	72.2	56.0				
1987	NA	NA	NA	NA	NA	NA	NA	NA	20.2	19.5	21.8	11.9	14.8	23.6	28.0	33.9	6.6	-42.8			
1988	NA	NA	NA	NA	NA	NA	NA	NA	19.6	19.0	21.0	12.2	14.7	22.0	25.2	28.9	9.1	-14.3	14.2		
1989	NA	NA	NA	NA	NA	NA	NA	NA	18.3	17.5	19.2	11.2	13.3	19.3	21.6	23.8	7.7	-8.4	8.8	3.3	
1990	NA	NA	NA	NA	NA	NA	NA	NA	13.8	12.7	13.8	6.0	7.3	11.9	12.7	13.1	-2.0	-16.4	-7.6	-18.6	-40.5
1991	NA	NA	NA	NA	NA	NA	NA	NA	11.9	10.8	11.6	4.4	5.3	9.2	9.6	9.5	-3.7	-15.6	-8.8	-16.4	-26.3
1992	NA	NA	NA	NA	NA	NA	NA	NA	10.2	9.0	9.6	2.8	3.5	6.8	6.9	6.5	-5.2	-15.4	-9.9	-16.0	-22.4
1993	NA	NA	NA	NA	NA	NA	NA	NA	11.9	10.9	11.7	5.5	6.4	9.7	10.1	10.0	0.2	-7.7	-1.9	-5.1	-7.2
1994	NA	NA	NA	NA	NA	NA	NA	NA	11.0	10.0	10.7	4.9	5.7	8.6	8.9	8.7	-0.2	-7.2	-2.1	-4.8	-6.4
1995	NA	NA	NA	NA	NA	NA	NA	NA	9.7	8.7	9.2	3.8	4.4	7.0	7.1	6.8	-1.4	-7.7	-3.3	-5.8	-7.4
1996	NA	NA	NA	NA	NA	NA	NA	NA	9.2	8.2	8.7	3.5	4.1	6.5	6.5	6.2	-1.3	-7.0	-3.0	-5.2	-6.4
1997	NA	NA	NA	NA	NA	NA	NA	NA	11.3	10.5	11.1	6.3	7.1	9.5	9.8	9.7	3.2	-1.6	2.5	1.2	0.9
1998	NA	NA	NA	NA	NA	NA	NA	NA	12.6	11.9	12.5	8.1	8.9	11.3	11.6	11.7	5.8	1.7	5.7	4.8	5.0
1999	NA	NA	NA	NA	NA	NA	NA	NA	12.7	12.0	12.6	8.4	9.2	11.5	11.8	11.9	6.4	2.6	6.4	5.7	6.0
2000	NA	NA	NA	NA	NA	NA	NA	NA	12.2	11.5	12.0	8.1	8.8	10.9	11.2	11.2	6.1	2.5	6.0	5.3	5.5
2001	NA	NA	NA	NA	NA	NA	NA	NA	10.6	9.9	10.3	6.4	7.0	8.9	9.1	9.0	4.1	0.6	3.7	2.9	2.9
2002	NA	NA	NA	NA	NA	NA	NA	NA	9.2	8.5	8.8	5.1	5.6	7.3	7.4	7.2	2.4	-0.9	1.9	1.0	0.8
2003	NA	NA	NA	NA	NA	NA	NA	NA	9.4	8.7	9.0	5.4	5.9	7.6	7.7	7.5	3.0	-0.1	2.6	1.8	1.7
2004	NA	NA	NA	NA	NA	NA	NA	NA	9.8	9.2	9.5	6.1	6.6	8.3	8.4	8.3	4.0	1.2	3.7	3.1	3.1
2005	NA	NA	NA	NA	NA	NA	NA	NA	10.1	9.5	9.8	6.5	7.0	8.6	8.7	8.7	4.7	2.0	4.5	3.9	3.9
2006	NA	NA	NA	NA	NA	NA	NA	NA	10.3	9.7	10.1	6.9	7.4	9.0	9.1	9.0	5.3	2.7	5.1	4.6	4.7
2007	NA	NA	NA	NA	NA	NA	NA	NA	9.7	9.1	9.4	6.4	6.9	8.3	8.4	8.3	4.7	2.2	4.5	4.0	4.0
2008	NA	NA	NA	NA	NA	NA	NA	NA	7.8	7.2	7.4	4.4	4.7	6.0	6.0	5.9	2.3	-0.2	1.9	1.2	1.1
2009	NA	NA	NA	NA	NA	NA	NA	NA	8.3	7.7	7.9	5.0	5.4	6.7	6.7	6.5	3.1	0.8	2.8	2.3	2.2
2010	NA	NA	NA	NA	NA	NA	NA	NA	7.7	7.1	7.3	4.5	4.9	6.1	6.1	5.9	2.6	0.4	2.3	1.8	1.7

Italy Short-Horizon Equity Risk Premia (in Local Currency)



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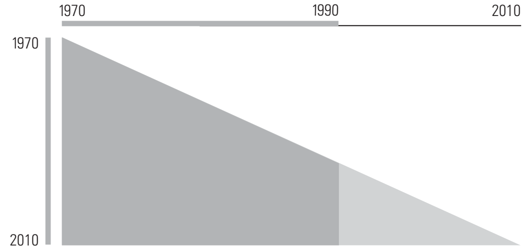
1991	-12.1																			
1992	-13.3	-14.5																		
1993	3.8	11.8	38.2																	
1994	2.1	6.8	17.5	-3.3																
1995	-0.8	2.1	7.6	-7.6	-12.0															
1996	-0.7	1.6	5.6	-5.3	-6.3	-0.5														
1997	6.8	10.0	14.9	9.0	13.1	25.7	51.9													
1998	10.7	14.0	18.7	14.8	19.3	29.8	44.9	38.0												
1999	11.1	14.0	18.1	14.7	18.3	25.9	34.7	26.2	14.4											
2000	10.1	12.6	16.0	12.8	15.5	21.0	26.4	17.9	7.9	1.3										
2001	6.8	8.7	11.3	7.9	9.5	13.1	15.8	6.8	-3.5	-12.5	-26.4									
2002	4.3	5.8	7.8	4.4	5.4	7.8	9.2	0.7	-8.6	-16.3	-25.1	-23.9								
2003	5.0	6.4	8.3	5.3	6.2	8.5	9.8	2.8	-4.2	-8.9	-12.3	-5.3	13.3							
2004	6.2	7.6	9.4	6.8	7.8	10.0	11.4	5.6	0.2	-2.7	-3.7	3.9	17.8	22.2						
2005	6.9	8.2	10.0	7.6	8.6	10.7	11.9	7.0	2.5	0.5	0.4	7.1	17.4	19.4	16.6					
2006	7.5	8.8	10.5	8.3	9.3	11.3	12.4	8.0	4.3	2.9	3.1	9.0	17.2	18.5	16.7	16.8				
2007	6.6	7.8	9.3	7.2	8.0	9.7	10.6	6.5	3.0	1.6	1.6	6.3	12.3	12.1	8.7	4.7	-7.4			
2008	3.5	4.4	5.6	3.4	3.8	5.1	5.5	1.3	-2.3	-4.2	-4.9	-1.8	1.8	-0.5	-6.1	-13.7	-29.0	-50.6		
2009	4.5	5.4	6.6	4.6	5.1	6.3	6.9	3.1	-0.1	-1.5	-1.8	1.3	4.9	3.4	-0.3	-4.6	-11.7	-13.8	22.9	
2010	3.8	4.6	5.7	3.8	4.2	5.3	5.7	2.2	-0.8	-2.2	-2.5	0.1	3.1	1.6	-1.8	-5.5	-11.0	-12.3	6.9	-9.2

Italy Short-Horizon Equity Risk Premia (in U.S. Dollars)



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1978	NA	NA	NA	NA	NA	NA	NA	NA	27.9												
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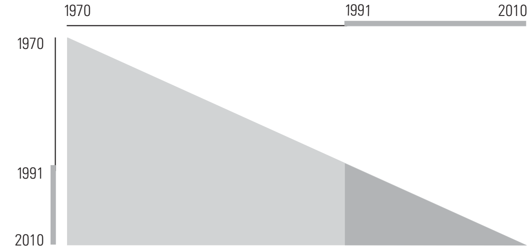
1980	NA	NA	NA	NA	NA	NA	NA	NA	35.9	39.9	79.1										
1981	NA	NA	NA	NA	NA	NA	NA	NA	25.9	25.2	37.4	-4.3									
1982	NA	NA	NA	NA	NA	NA	NA	NA	15.6	12.5	16.4	-14.9	-25.6								
1983	NA	NA	NA	NA	NA	NA	NA	NA	13.8	11.0	13.5	-8.3	-10.4	4.9							
1984	NA	NA	NA	NA	NA	NA	NA	NA	13.1	10.6	12.6	-4.0	-3.9	7.0	9.0						
1985	NA	NA	NA	NA	NA	NA	NA	NA	24.1	23.6	27.4	17.1	22.4	38.4	55.1	101.2					
1986	NA	NA	NA	NA	NA	NA	NA	NA	29.3	29.4	33.5	26.0	32.0	46.4	60.2	85.8	70.5				
1987	NA	NA	NA	NA	NA	NA	NA	NA	21.2	20.5	22.9	14.9	18.1	26.9	32.4	40.1	9.6	-51.3			
1988	NA	NA	NA	NA	NA	NA	NA	NA	20.5	19.8	21.9	14.7	17.4	24.6	28.6	33.4	10.9	-19.0	13.4		
1989	NA	NA	NA	NA	NA	NA	NA	NA	19.1	18.3	20.0	13.5	15.7	21.6	24.4	27.5	9.0	-11.5	8.5	3.5	
1990	NA	NA	NA	NA	NA	NA	NA	NA	14.1	13.0	14.1	7.6	8.9	13.2	14.4	15.3	-1.9	-20.0	-9.6	-21.1	-45.6
1991	NA	NA	NA	NA	NA	NA	NA	NA	12.2	11.0	11.9	5.8	6.8	10.4	11.1	11.4	-3.6	-18.4	-10.2	-18.1	-28.9
1992	NA	NA	NA	NA	NA	NA	NA	NA	10.7	9.5	10.1	4.4	5.2	8.3	8.6	8.6	-4.7	-17.2	-10.3	-16.3	-22.9
1993	NA	NA	NA	NA	NA	NA	NA	NA	12.1	11.0	11.8	6.6	7.5	10.5	11.1	11.3	0.1	-10.0	-3.1	-6.4	-8.9
1994	NA	NA	NA	NA	NA	NA	NA	NA	11.2	10.1	10.7	5.9	6.7	9.3	9.7	9.8	-0.3	-9.2	-3.2	-5.9	-7.8
1995	NA	NA	NA	NA	NA	NA	NA	NA	9.9	8.8	9.3	4.7	5.3	7.7	7.9	7.8	-1.5	-9.5	-4.3	-6.8	-8.6
1996	NA	NA	NA	NA	NA	NA	NA	NA	9.3	8.3	8.7	4.3	4.9	7.1	7.2	7.1	-1.5	-8.7	-3.9	-6.1	-7.5
1997	NA	NA	NA	NA	NA	NA	NA	NA	11.1	10.2	10.7	6.7	7.4	9.6	9.9	10.0	2.4	-3.8	1.0	-0.4	-0.9
1998	NA	NA	NA	NA	NA	NA	NA	NA	12.5	11.7	12.3	8.6	9.3	11.5	12.0	12.2	5.3	-0.1	4.5	3.7	3.7
1999	NA	NA	NA	NA	NA	NA	NA	NA	12.4	11.7	12.2	8.7	9.5	11.5	11.9	12.1	5.8	0.8	5.1	4.4	4.4
2000	NA	NA	NA	NA	NA	NA	NA	NA	12.0	11.2	11.7	8.4	9.0	11.0	11.3	11.5	5.5	0.8	4.8	4.1	4.2
2001	NA	NA	NA	NA	NA	NA	NA	NA	10.4	9.7	10.1	6.8	7.3	9.1	9.3	9.3	3.6	-0.9	2.7	1.9	1.8
2002	NA	NA	NA	NA	NA	NA	NA	NA	8.9	8.1	8.4	5.2	5.7	7.2	7.3	7.2	1.7	-2.6	0.7	-0.2	-0.5
2003	NA	NA	NA	NA	NA	NA	NA	NA	9.2	8.4	8.8	5.7	6.1	7.7	7.8	7.7	2.5	-1.5	1.7	0.9	0.7
2004	NA	NA	NA	NA	NA	NA	NA	NA	9.7	9.0	9.4	6.5	6.9	8.4	8.6	8.5	3.7	-0.1	3.0	2.3	2.2
2005	NA	NA	NA	NA	NA	NA	NA	NA	9.9	9.2	9.5	6.8	7.2	8.6	8.8	8.8	4.2	0.7	3.6	3.0	3.0
2006	NA	NA	NA	NA	NA	NA	NA	NA	10.2	9.6	9.9	7.2	7.7	9.1	9.3	9.3	4.9	1.6	4.4	3.9	3.9
2007	NA	NA	NA	NA	NA	NA	NA	NA	9.6	9.0	9.3	6.7	7.1	8.4	8.5	8.5	4.3	1.2	3.8	3.3	3.3
2008	NA	NA	NA	NA	NA	NA	NA	NA	7.7	7.0	7.3	4.7	5.0	6.2	6.2	6.1	2.0	-1.1	1.3	0.7	0.5
2009	NA	NA	NA	NA	NA	NA	NA	NA	8.2	7.6	7.8	5.4	5.7	6.9	6.9	6.9	2.9	0.0	2.3	1.8	1.7
2010	NA	NA	NA	NA	NA	NA	NA	NA	7.7	7.1	7.3	4.9	5.2	6.3	6.4	6.3	2.5	-0.4	1.9	1.3	1.2

Italy Short-Horizon Equity Risk Premia (in U.S. Dollars)



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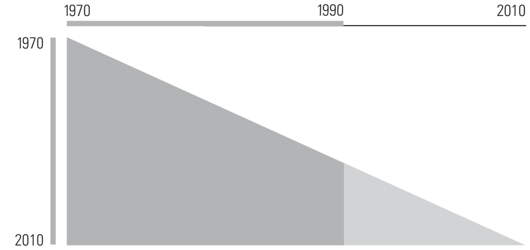
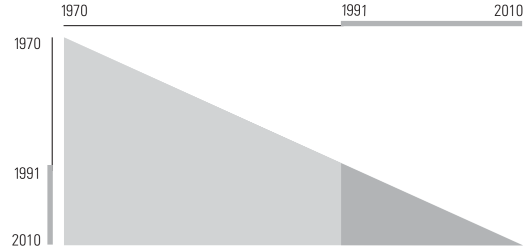
1992	-11.5	-10.9																		
1993	3.3	11.0	33.0																	
1994	1.6	6.2	14.8	-3.5																
1995	-1.2	1.6	5.8	-7.9	-12.2															
1996	-1.1	1.1	4.1	-5.5	-6.5	-0.8														
1997	5.5	8.4	12.3	7.1	10.6	22.0	44.8													
1998	9.8	13.0	17.0	13.7	18.1	28.1	42.6	40.5												
1999	10.0	12.8	16.2	13.4	16.7	24.0	32.2	25.9	11.4											
2000	9.2	11.5	14.3	11.7	14.2	19.5	24.5	17.8	6.5	1.5										
2001	6.1	7.9	10.0	7.1	8.6	12.1	14.7	7.2	-3.9	-11.6	-24.7									
2002	3.2	4.6	6.2	3.2	4.0	6.4	7.6	0.1	-10.0	-17.1	-26.4	-28.1								
2003	4.3	5.6	7.1	4.5	5.4	7.6	8.8	2.8	-4.7	-8.7	-12.1	-5.8	16.4							
2004	5.6	7.0	8.5	6.3	7.3	9.4	10.7	5.8	0.1	-2.2	-3.1	4.1	20.1	23.8						
2005	6.2	7.5	8.9	6.9	7.9	9.9	11.1	6.9	2.0	0.5	0.3	6.5	18.1	18.9	13.9					
2006	7.0	8.3	9.7	7.9	8.8	10.7	11.9	8.2	4.2	3.1	3.4	9.0	18.3	18.9	16.5	19.1				
2007	6.1	7.3	8.5	6.7	7.5	9.2	10.1	6.6	2.8	1.8	1.8	6.2	13.1	12.2	8.4	5.6	-7.9			
2008	3.1	4.0	4.9	3.0	3.5	4.7	5.2	1.6	-2.3	-3.8	-4.5	-1.6	2.8	0.1	-5.9	-12.5	-28.3	-48.7		
2009	4.2	5.1	6.1	4.4	4.9	6.1	6.7	3.5	0.1	-1.0	-1.3	1.6	5.9	4.1	0.2	-3.3	-10.7	-12.2	24.4	
2010	3.6	4.4	5.3	3.6	4.1	5.1	5.6	2.6	-0.6	-1.7	-2.0	0.5	4.1	2.3	-1.3	-4.3	-10.2	-10.9	8.0	-8.4

Japan Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-18.5																				
1971	4.8	28.2																			
1972	39.9	69.1	110.1																		
1973	21.8	35.2	38.7	-32.6																	
1974	13.8	21.8	19.7	-25.5	-18.4																
1975	13.5	19.9	17.8	-12.9	-3.1	12.2															
1976	13.3	18.6	16.6	-6.7	1.9	12.0	11.9														
1977	10.0	14.0	11.7	-8.0	-1.9	3.6	-0.6	-13.1													
1978	10.9	14.5	12.6	-3.6	2.1	7.3	5.6	2.5	18.1												
1979	10.0	13.1	11.3	-2.9	2.1	6.2	4.7	2.3	10.0	1.8											
1980	9.2	12.0	10.2	-2.3	2.1	5.5	4.1	2.2	7.3	1.9	1.9										
1981	9.8	12.4	10.8	-0.2	3.8	7.0	6.1	4.9	9.5	6.6	8.9	16.0									
1982	8.9	11.2	9.7	-0.4	3.2	5.9	5.0	3.8	7.2	4.5	5.4	7.2	-1.7								
1983	9.4	11.5	10.2	1.1	4.4	7.0	6.3	5.5	8.6	6.7	8.0	10.0	7.0	15.7							
1984	10.1	12.2	10.9	2.7	5.9	8.3	7.9	7.4	10.3	9.0	10.4	12.5	11.4	17.9	20.2						
1985	10.0	11.9	10.7	3.1	6.1	8.3	7.9	7.5	10.0	8.9	10.0	11.7	10.6	14.7	14.2	8.3					
1986	12.6	14.5	13.6	6.7	9.7	12.1	12.1	12.1	14.9	14.5	16.3	18.7	19.2	24.4	27.4	31.0	53.6				
1987	12.1	13.9	13.0	6.6	9.3	11.5	11.4	11.4	13.8	13.4	14.8	16.6	16.7	20.4	21.6	22.1	29.0	4.4			
1988	13.3	15.1	14.3	8.4	11.1	13.2	13.3	13.4	15.8	15.6	17.1	19.0	19.4	22.9	24.4	25.4	31.2	19.9	35.4		
1989	13.3	15.0	14.2	8.6	11.2	13.1	13.2	13.3	15.5	15.3	16.6	18.3	18.5	21.4	22.4	22.8	26.5	17.4	23.9	12.5	
1990	10.5	11.9	11.1	5.6	7.8	9.4	9.3	9.1	10.8	10.2	10.9	11.8	11.4	13.0	12.6	11.3	12.0	1.5	0.6	-16.8	-46.1
1991	9.7	11.0	10.2	4.9	7.0	8.5	8.3	8.0	9.5	8.9	9.5	10.2	9.6	10.8	10.2	8.8	8.9	-0.1	-1.2	-13.4	-26.3
1992	8.1	9.3	8.4	3.3	5.2	6.5	6.2	5.9	7.1	6.3	6.7	7.1	6.3	7.1	6.1	4.4	3.8	-4.5	-6.3	-16.7	-26.4
1993	8.1	9.3	8.4	3.6	5.4	6.6	6.3	6.0	7.2	6.5	6.8	7.2	6.5	7.2	6.4	4.8	4.4	-2.7	-3.8	-11.7	-17.7
1994	8.0	9.1	8.3	3.7	5.4	6.6	6.3	6.0	7.1	6.4	6.7	7.1	6.4	7.1	6.3	4.9	4.5	-1.6	-2.5	-8.8	-13.1
1995	7.8	8.8	8.0	3.6	5.2	6.3	6.0	5.7	6.8	6.1	6.4	6.7	6.0	6.6	5.9	4.6	4.2	-1.3	-2.0	-7.4	-10.7
1996	7.2	8.2	7.4	3.1	4.7	5.7	5.4	5.1	6.1	5.4	5.6	5.8	5.2	5.6	4.9	3.6	3.2	-1.9	-2.6	-7.3	-10.1
1997	6.4	7.3	6.5	2.4	3.8	4.8	4.4	4.1	4.9	4.3	4.4	4.5	3.8	4.2	3.4	2.1	1.6	-3.2	-3.9	-8.3	-10.9
1998	5.8	6.7	5.9	1.9	3.3	4.2	3.8	3.5	4.2	3.6	3.6	3.7	3.0	3.3	2.5	1.2	0.7	-3.7	-4.5	-8.5	-10.8
1999	7.1	8.0	7.3	3.5	4.9	5.8	5.5	5.3	6.1	5.5	5.7	5.9	5.3	5.8	5.1	4.1	3.8	0.0	-0.3	-3.6	-5.2
2000	6.2	7.0	6.3	2.6	3.9	4.8	4.5	4.1	4.9	4.3	4.4	4.5	3.9	4.3	3.6	2.5	2.2	-1.5	-2.0	-5.1	-6.7
2001	5.4	6.2	5.4	1.8	3.0	3.8	3.5	3.2	3.9	3.2	3.3	3.4	2.7	3.0	2.3	1.2	0.8	-2.8	-3.3	-6.3	-7.8
2002	4.6	5.3	4.6	1.1	2.2	3.0	2.6	2.3	2.9	2.3	2.3	2.3	1.7	1.8	1.1	0.0	-0.5	-3.8	-4.4	-7.2	-8.7
2003	5.1	5.8	5.1	1.8	2.9	3.6	3.3	3.0	3.6	3.1	3.1	3.2	2.6	2.8	2.1	1.2	0.8	-2.3	-2.7	-5.3	-6.5
2004	5.2	5.9	5.3	2.0	3.1	3.8	3.5	3.2	3.8	3.3	3.4	3.4	2.9	3.1	2.5	1.6	1.2	-1.7	-2.0	-4.4	-5.5
2005	6.3	7.0	6.4	3.3	4.4	5.1	4.9	4.6	5.3	4.8	4.9	5.0	4.6	4.8	4.3	3.6	3.4	0.7	0.5	-1.6	-2.4
2006	6.3	7.0	6.4	3.3	4.4	5.1	4.9	4.7	5.3	4.8	4.9	5.0	4.6	4.9	4.4	3.7	3.5	1.0	0.8	-1.2	-2.0
2007	5.8	6.5	5.9	2.9	3.9	4.6	4.4	4.1	4.7	4.2	4.3	4.4	4.0	4.2	3.7	3.0	2.8	0.3	0.1	-1.7	-2.5
2008	4.5	5.1	4.5	1.6	2.6	3.2	2.9	2.6	3.1	2.6	2.7	2.7	2.2	2.3	1.8	1.1	0.7	-1.7	-2.0	-3.8	-4.7
2009	4.6	5.2	4.6	1.8	2.7	3.3	3.1	2.8	3.3	2.8	2.8	2.9	2.4	2.6	2.1	1.3	1.0	-1.3	-1.5	-3.3	-4.1
2010	4.5	5.1	4.5	1.7	2.6	3.2	3.0	2.7	3.2	2.7	2.7	2.8	2.3	2.4	2.0	1.3	1.0	-1.2	-1.5	-3.1	-3.9

Japan Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
1972																				
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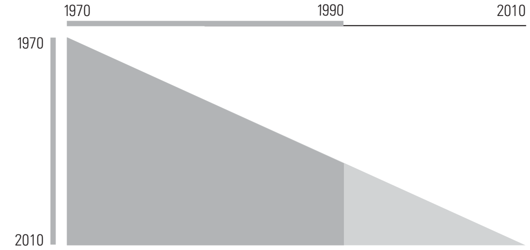
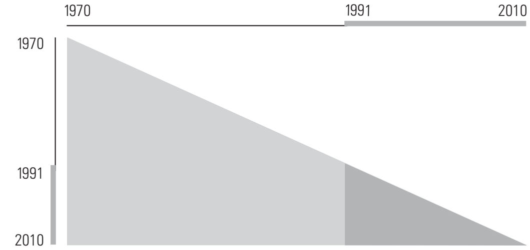
1990																				
1991	-6.6																			
1992	-16.6	-26.6																		
1993	-8.2	-9.1	8.4																	
1994	-4.8	-4.2	6.9	5.4																
1995	-3.6	-2.8	5.1	3.4	1.4															
1996	-4.2	-3.7	2.1	-0.1	-2.8	-7.0														
1997	-5.9	-5.7	-1.6	-4.1	-7.3	-11.6	-16.1													
1998	-6.4	-6.3	-3.0	-5.2	-7.9	-11.0	-13.0	-9.8												
1999	-0.7	0.1	3.9	3.1	2.7	3.0	6.3	17.6	45.0											
2000	-2.7	-2.3	0.7	-0.4	-1.4	-1.9	-0.6	4.6	11.7	-21.5										
2001	-4.3	-4.1	-1.6	-2.9	-4.0	-4.9	-4.5	-1.6	1.1	-20.9	-20.2									
2002	-5.6	-5.5	-3.4	-4.8	-6.0	-7.1	-7.1	-5.3	-4.2	-20.5	-20.1	-19.9								
2003	-3.5	-3.2	-1.1	-2.1	-2.9	-3.4	-2.9	-0.7	1.1	-9.9	-6.0	1.0	22.0							
2004	-2.6	-2.3	-0.2	-1.0	-1.7	-2.0	-1.4	0.7	2.5	-6.0	-2.2	3.8	15.7	9.4						
2005	0.5	1.0	3.1	2.7	2.4	2.5	3.6	6.0	8.3	2.2	6.9	13.7	24.9	26.4	43.3					
2006	0.8	1.3	3.3	2.9	2.7	2.8	3.8	6.0	8.0	2.7	6.7	12.1	20.1	19.5	24.5	5.7				
2007	0.1	0.5	2.3	1.8	1.6	1.6	2.4	4.2	5.8	0.9	4.1	8.1	13.7	11.7	12.4	-3.1	-11.8			
2008	-2.4	-2.1	-0.6	-1.2	-1.7	-1.9	-1.5	-0.2	0.8	-4.1	-1.9	0.7	4.1	0.5	-1.7	-16.7	-27.9	-44.0		
2009	-1.8	-1.6	-0.1	-0.6	-1.0	-1.2	-0.8	0.5	1.5	-2.9	-0.8	1.6	4.7	1.8	0.2	-10.5	-15.9	-18.0	8.0	
2010	-1.8	-1.5	-0.1	-0.6	-1.0	-1.2	-0.7	0.4	1.3	-2.7	-0.8	1.4	4.0	1.4	0.1	-8.5	-12.1	-12.2	3.7	-0.5

Japan Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-18.5																				
1971	13.6	45.6																			
1972	48.7	82.3	119.0																		
1973	29.7	45.8	45.8	-27.3																	
1974	19.0	28.3	22.6	-25.7	-24.0																
1975	17.6	24.8	19.6	-13.6	-6.7	10.7															
1976	17.4	23.4	19.0	-6.0	1.1	13.6	16.6														
1977	16.0	20.9	16.8	-3.6	2.3	11.1	11.3	6.0													
1978	19.3	24.0	20.9	4.6	11.0	19.7	22.7	25.8	45.6												
1979	15.6	19.4	16.2	1.5	6.3	12.3	12.7	11.4	14.2	-17.3											
1980	16.1	19.5	16.6	3.8	8.3	13.6	14.2	13.6	16.2	1.5	20.3										
1981	15.3	18.4	15.7	4.2	8.1	12.7	13.0	12.3	13.9	3.4	13.7	7.1									
1982	13.5	16.2	13.5	3.0	6.3	10.1	10.0	8.9	9.5	0.5	6.5	-0.5	-8.0								
1983	13.8	16.3	13.8	4.2	7.4	10.9	10.9	10.1	10.8	3.8	9.1	5.4	4.5	17.1							
1984	13.6	15.9	13.6	4.8	7.7	10.9	10.9	10.2	10.8	5.0	9.5	6.8	6.7	14.1	11.1						
1985	15.0	17.2	15.2	7.2	10.1	13.2	13.4	13.1	13.9	9.4	13.9	12.6	13.9	21.3	23.4	35.6					
1986	19.6	22.0	20.4	13.4	16.5	19.9	20.7	21.1	22.8	19.9	25.3	26.1	29.9	39.4	46.8	64.6	93.6				
1987	20.6	22.9	21.5	15.0	18.0	21.2	22.1	22.6	24.2	21.9	26.8	27.7	31.1	38.9	44.4	55.5	65.5	37.3			
1988	21.1	23.3	22.0	16.0	18.8	21.9	22.8	23.3	24.9	22.8	27.2	28.1	31.1	37.6	41.7	49.4	54.0	34.2	31.1		
1989	20.0	22.0	20.7	14.9	17.5	20.3	21.0	21.3	22.6	20.5	24.3	24.7	26.9	31.9	34.4	39.1	39.9	22.1	14.4	-2.2	
1990	17.0	18.7	17.3	11.7	14.0	16.3	16.7	16.7	17.6	15.2	18.2	18.0	19.2	22.6	23.4	25.4	23.4	5.8	-4.7	-22.6	-42.9
1991	16.3	17.9	16.5	11.2	13.3	15.5	15.8	15.7	16.4	14.2	16.8	16.5	17.4	20.3	20.7	22.0	19.8	5.0	-3.1	-14.5	-20.6
1992	14.4	15.9	14.5	9.3	11.2	13.1	13.3	13.1	13.6	11.3	13.5	12.9	13.4	15.6	15.4	15.9	13.1	-0.3	-7.8	-17.5	-22.6
1993	14.7	16.1	14.8	9.8	11.7	13.6	13.7	13.6	14.0	11.9	14.0	13.5	14.1	16.1	16.0	16.5	14.1	2.8	-3.0	-9.8	-11.7
1994	14.8	16.2	14.9	10.2	12.0	13.8	14.0	13.8	14.3	12.3	14.3	13.9	14.4	16.3	16.2	16.7	14.6	4.7	0.1	-5.1	-5.7
1995	14.2	15.5	14.2	9.7	11.3	13.0	13.1	13.0	13.4	11.5	13.3	12.8	13.2	14.8	14.6	15.0	12.9	3.9	-0.3	-4.7	-5.1
1996	13.0	14.2	13.0	8.6	10.1	11.7	11.7	11.5	11.8	9.9	11.5	10.9	11.2	12.6	12.2	12.3	10.2	1.8	-2.1	-6.3	-6.8
1997	11.6	12.8	11.5	7.2	8.6	10.0	10.0	9.7	9.9	8.0	9.4	8.8	8.9	10.0	9.5	9.4	7.2	-0.7	-4.5	-8.4	-9.2
1998	11.4	12.4	11.2	7.1	8.4	9.8	9.7	9.4	9.6	7.8	9.1	8.5	8.6	9.6	9.1	9.0	6.9	-0.3	-3.7	-7.2	-7.7
1999	13.0	14.1	13.0	9.1	10.5	11.8	11.9	11.7	11.9	10.3	11.7	11.3	11.5	12.6	12.4	12.5	10.8	4.4	1.7	-1.0	-0.9
2000	11.6	12.6	11.5	7.7	9.0	10.2	10.2	9.9	10.1	8.5	9.7	9.2	9.3	10.3	9.9	9.8	8.1	2.0	-0.7	-3.4	-3.5
2001	10.3	11.2	10.1	6.3	7.5	8.7	8.6	8.3	8.4	6.8	7.9	7.3	7.3	8.1	7.6	7.4	5.7	-0.2	-2.9	-5.5	-5.8
2002	9.7	10.5	9.4	5.8	6.9	8.0	7.9	7.6	7.6	6.1	7.1	6.5	6.4	7.2	6.6	6.4	4.7	-0.9	-3.4	-5.9	-6.2
2003	10.4	11.3	10.2	6.7	7.8	8.9	8.9	8.6	8.7	7.2	8.2	7.7	7.7	8.5	8.1	7.9	6.4	1.2	-1.0	-3.2	-3.2
2004	10.5	11.4	10.3	7.0	8.1	9.1	9.1	8.8	8.9	7.5	8.5	8.0	8.0	8.8	8.4	8.2	6.8	2.0	-0.1	-2.1	-2.0
2005	10.9	11.8	10.8	7.5	8.6	9.6	9.6	9.3	9.5	8.1	9.1	8.7	8.7	9.4	9.1	9.0	7.7	3.2	1.3	-0.5	-0.4
2006	10.7	11.6	10.6	7.4	8.5	9.5	9.4	9.2	9.3	8.0	8.9	8.5	8.6	9.3	8.9	8.8	7.5	3.2	1.4	-0.2	-0.1
2007	10.3	11.1	10.1	7.0	8.0	9.0	9.0	8.7	8.8	7.5	8.4	8.0	8.0	8.6	8.3	8.2	6.9	2.8	1.1	-0.5	-0.4
2008	9.3	10.0	9.0	6.0	6.9	7.8	7.7	7.5	7.5	6.2	7.0	6.6	6.6	7.1	6.7	6.5	5.3	1.3	-0.5	-2.0	-2.0
2009	9.1	9.9	8.9	5.9	6.9	7.7	7.7	7.4	7.4	6.2	7.0	6.5	6.5	7.0	6.7	6.5	5.3	1.4	-0.2	-1.7	-1.7
2010	9.3	10.0	9.0	6.2	7.1	7.9	7.8	7.6	7.6	6.4	7.2	6.8	6.8	7.3	6.9	6.8	5.6	2.0	0.4	-1.0	-0.9

Japan Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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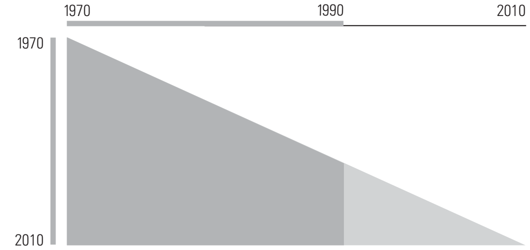
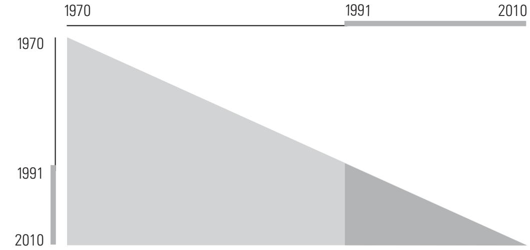
1991	1.7																			
1992	-12.5	-26.6																		
1993	-1.2	-2.7	21.3																	
1994	3.6	4.3	19.7	18.1																
1995	2.4	2.6	12.3	7.9	-2.4															
1996	-0.8	-1.3	5.0	-0.4	-9.7	-17.0														
1997	-4.4	-5.4	-1.1	-6.7	-15.0	-21.3	-25.6													
1998	-3.3	-4.1	-0.3	-4.6	-10.3	-12.9	-10.9	3.8												
1999	3.8	4.1	8.5	6.3	4.0	5.6	13.1	32.4	61.1											
2000	0.4	0.3	3.7	1.2	-1.7	-1.5	2.3	11.6	15.6	-29.9										
2001	-2.4	-2.8	-0.1	-2.8	-5.8	-6.4	-4.3	1.1	0.2	-30.3	-30.7									
2002	-3.1	-3.6	-1.3	-3.8	-6.5	-7.1	-5.4	-1.4	-2.7	-23.9	-21.0	-11.2								
2003	-0.2	-0.3	2.0	0.1	-1.9	-1.8	0.3	4.7	4.8	-9.2	-2.3	11.9	34.9							
2004	0.9	0.8	3.1	1.4	-0.2	0.0	2.1	6.1	6.5	-4.4	1.9	12.8	24.8	14.7						
2005	2.4	2.5	4.7	3.4	2.0	2.5	4.6	8.4	9.1	0.4	6.4	15.7	24.7	19.6	24.5					
2006	2.6	2.6	4.7	3.5	2.2	2.7	4.6	8.0	8.5	1.0	6.1	13.5	19.7	14.6	14.6	4.7				
2007	2.1	2.1	4.0	2.8	1.6	2.0	3.7	6.6	6.9	0.2	4.4	10.3	14.6	9.5	7.8	-0.5	-5.8			
2008	0.2	0.2	1.8	0.5	-0.7	-0.6	0.8	3.2	3.1	-3.3	0.0	4.4	7.0	1.4	-1.9	-10.8	-18.5	-31.2		
2009	0.5	0.4	2.0	0.8	-0.3	-0.2	1.1	3.3	3.3	-2.5	0.6	4.5	6.7	2.0	-0.5	-6.8	-10.6	-13.0	5.2	
2010	1.2	1.2	2.7	1.6	0.6	0.8	2.0	4.2	4.2	-1.0	1.9	5.5	7.6	3.7	1.9	-2.6	-4.4	-4.0	9.6	14.1

Japan Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-20.1																				
1971	4.2	28.6																			
1972	40.2	70.4	112.1																		
1973	22.0	36.0	39.7	-32.8																	
1974	13.1	21.3	18.9	-27.7	-22.6																
1975	12.5	19.0	16.7	-15.2	-6.4	9.8															
1976	12.7	18.1	16.0	-8.0	0.2	11.6	13.4														
1977	9.7	13.9	11.5	-8.6	-2.6	4.1	1.2	-11.1													
1978	10.8	14.7	12.7	-3.9	1.9	8.0	7.4	4.4	19.8												
1979	10.0	13.4	11.5	-2.9	2.0	7.0	6.3	3.9	11.3	2.8											
1980	9.0	11.9	10.1	-2.7	1.6	5.7	4.8	2.7	7.3	1.0	-0.8										
1981	9.7	12.4	10.8	-0.5	3.6	7.3	6.9	5.6	9.7	6.4	8.2	17.2									
1982	8.9	11.3	9.7	-0.5	3.1	6.3	5.8	4.5	7.6	4.6	5.2	8.1	-0.9								
1983	9.4	11.7	10.3	1.0	4.4	7.4	7.1	6.2	9.1	7.0	8.0	10.9	7.8	16.5							
1984	10.2	12.4	11.1	2.7	5.9	8.8	8.6	8.0	10.8	9.3	10.5	13.4	12.1	18.6	20.7						
1985	10.1	12.1	10.9	3.1	6.1	8.7	8.6	8.0	10.4	9.1	10.1	12.3	11.1	15.1	14.4	8.0					
1986	12.6	14.7	13.7	6.7	9.7	12.4	12.7	12.6	15.2	14.6	16.3	19.2	19.6	24.7	27.4	30.8	53.5				
1987	12.2	14.1	13.2	6.6	9.4	11.9	12.0	11.9	14.2	13.6	14.9	17.1	17.1	20.8	21.8	22.2	29.3	5.0			
1988	13.4	15.3	14.5	8.4	11.2	13.6	13.8	13.9	16.1	15.8	17.2	19.5	19.8	23.3	24.6	25.6	31.4	20.4	35.8		
1989	13.4	15.1	14.4	8.6	11.2	13.5	13.7	13.7	15.8	15.4	16.7	18.6	18.8	21.6	22.5	22.9	26.6	17.6	23.9	12.0	
1990	10.5	12.0	11.1	5.5	7.8	9.7	9.7	9.4	11.0	10.2	10.9	12.1	11.5	13.1	12.6	11.2	11.8	1.4	0.2	-17.6	-47.1
1991	9.6	11.1	10.2	4.8	6.9	8.6	8.6	8.2	9.6	8.8	9.3	10.3	9.6	10.7	10.0	8.5	8.6	-0.4	-1.8	-14.3	-27.4
1992	8.1	9.4	8.4	3.3	5.2	6.7	6.5	6.1	7.2	6.3	6.6	7.2	6.3	7.0	6.0	4.1	3.6	-4.7	-6.7	-17.3	-27.1
1993	8.1	9.4	8.5	3.5	5.4	6.8	6.7	6.3	7.3	6.5	6.8	7.4	6.6	7.2	6.3	4.7	4.3	-2.8	-4.0	-12.0	-18.0
1994	8.1	9.2	8.4	3.7	5.4	6.8	6.7	6.3	7.3	6.5	6.8	7.3	6.5	7.2	6.3	4.9	4.5	-1.6	-2.5	-8.9	-13.1
1995	7.9	9.0	8.2	3.6	5.3	6.6	6.5	6.1	7.1	6.3	6.5	7.0	6.3	6.8	6.0	4.7	4.4	-1.1	-1.9	-7.2	-10.4
1996	7.4	8.4	7.6	3.3	4.8	6.1	5.9	5.5	6.4	5.7	5.8	6.2	5.5	6.0	5.2	3.9	3.5	-1.5	-2.2	-7.0	-9.7
1997	6.6	7.6	6.8	2.6	4.0	5.2	5.0	4.6	5.3	4.6	4.7	5.0	4.2	4.6	3.7	2.4	2.0	-2.7	-3.5	-7.9	-10.3
1998	6.0	7.0	6.2	2.1	3.5	4.6	4.4	3.9	4.7	3.9	4.0	4.2	3.5	3.7	2.9	1.6	1.1	-3.3	-4.0	-8.0	-10.2
1999	7.4	8.3	7.6	3.8	5.2	6.3	6.1	5.8	6.6	5.9	6.1	6.5	5.9	6.3	5.6	4.6	4.4	0.6	0.2	-3.0	-4.5
2000	6.5	7.4	6.7	2.9	4.2	5.3	5.1	4.7	5.4	4.8	4.9	5.1	4.5	4.8	4.1	3.1	2.8	-0.9	-1.3	-4.4	-5.9
2001	5.7	6.6	5.8	2.2	3.4	4.4	4.2	3.8	4.4	3.7	3.8	4.0	3.3	3.6	2.8	1.8	1.4	-2.1	-2.6	-5.5	-7.0
2002	5.0	5.8	5.0	1.5	2.6	3.5	3.3	2.9	3.5	2.8	2.8	3.0	2.3	2.5	1.7	0.7	0.2	-3.1	-3.6	-6.5	-7.9
2003	5.5	6.3	5.6	2.2	3.3	4.2	4.0	3.7	4.2	3.6	3.6	3.8	3.2	3.4	2.8	1.8	1.5	-1.6	-2.0	-4.5	-5.7
2004	5.7	6.4	5.8	2.4	3.6	4.4	4.3	3.9	4.5	3.9	3.9	4.1	3.6	3.8	3.2	2.3	2.0	-0.9	-1.2	-3.5	-4.6
2005	6.8	7.5	6.9	3.7	4.9	5.7	5.6	5.3	5.9	5.4	5.5	5.8	5.3	5.5	5.0	4.3	4.1	1.5	1.3	-0.7	-1.5
2006	6.8	7.5	6.9	3.8	4.9	5.8	5.7	5.4	6.0	5.5	5.6	5.8	5.4	5.6	5.1	4.4	4.3	1.8	1.6	-0.3	-1.0
2007	6.3	7.0	6.4	3.4	4.5	5.3	5.1	4.9	5.4	4.9	5.0	5.2	4.7	5.0	4.5	3.8	3.6	1.2	1.0	-0.8	-1.5
2008	5.0	5.7	5.1	2.1	3.1	3.9	3.7	3.4	3.9	3.3	3.3	3.5	3.0	3.1	2.6	1.8	1.6	-0.8	-1.1	-2.9	-3.7
2009	5.2	5.8	5.2	2.3	3.3	4.0	3.9	3.6	4.0	3.5	3.5	3.7	3.2	3.3	2.8	2.1	1.9	-0.4	-0.6	-2.3	-3.1
2010	5.0	5.7	5.1	2.3	3.2	3.9	3.8	3.5	3.9	3.4	3.4	3.6	3.1	3.3	2.8	2.1	1.8	-0.3	-0.6	-2.2	-2.9

Japan Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
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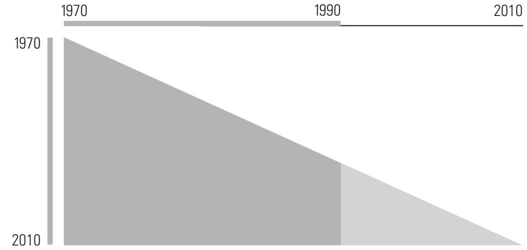
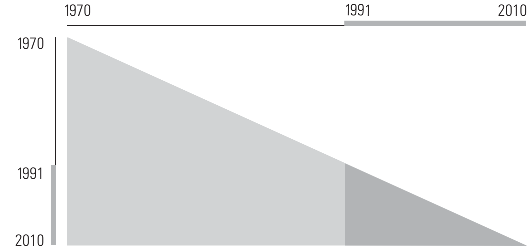
1991	-7.7																			
1992	-17.1	-26.4																		
1993	-8.3	-8.6	9.2																	
1994	-4.6	-3.6	7.8	6.5																
1995	-3.1	-1.9	6.2	4.7	2.9															
1996	-3.5	-2.6	3.3	1.4	-1.2	-5.3														
1997	-5.1	-4.7	-0.3	-2.7	-5.7	-10.1	-14.8													
1998	-5.6	-5.3	-1.8	-4.0	-6.6	-9.7	-12.0	-9.1												
1999	0.2	1.2	5.2	4.5	4.1	4.4	7.6	18.8	46.7											
2000	-1.8	-1.1	2.0	1.0	0.1	-0.5	0.7	5.9	13.4	-19.8										
2001	-3.3	-2.9	-0.3	-1.5	-2.6	-3.5	-3.2	-0.3	2.7	-19.4	-18.9									
2002	-4.6	-4.3	-2.1	-3.4	-4.6	-5.7	-5.8	-3.9	-2.7	-19.1	-18.8	-18.6								
2003	-2.5	-2.1	0.2	-0.7	-1.6	-2.1	-1.7	0.5	2.5	-8.6	-4.9	2.2	23.0							
2004	-1.5	-1.1	1.0	0.3	-0.3	-0.7	-0.1	2.0	3.9	-4.7	-0.9	5.1	16.9	10.9						
2005	1.5	2.2	4.4	4.0	3.8	3.9	4.9	7.3	9.7	3.5	8.2	15.0	26.2	27.8	44.7					
2006	1.9	2.5	4.6	4.3	4.1	4.2	5.1	7.3	9.4	4.1	8.0	13.4	21.4	20.9	26.0	7.2				
2007	1.2	1.7	3.6	3.2	2.9	2.9	3.7	5.5	7.2	2.2	5.4	9.4	15.0	13.1	13.8	-1.7	-10.6			
2008	-1.3	-0.9	0.7	0.1	-0.3	-0.6	-0.2	1.1	2.2	-2.8	-0.7	1.9	5.4	1.9	-0.4	-15.4	-26.8	-43.0		
2009	-0.7	-0.3	1.2	0.7	0.3	0.1	0.5	1.8	2.8	-1.6	0.4	2.8	5.9	3.1	1.5	-9.3	-14.8	-16.9	9.1	
2010	-0.7	-0.3	1.2	0.7	0.3	0.1	0.5	1.7	2.6	-1.4	0.4	2.6	5.2	2.7	1.4	-7.3	-10.9	-11.1	4.9	0.6

Japan Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-20.1																				
1971	6.2	32.5																			
1972	43.1	74.7	116.9																		
1973	23.5	38.0	40.8	-35.4																	
1974	14.6	23.3	20.2	-28.2	-21.0																
1975	13.8	20.5	17.6	-15.6	-5.7	9.7															
1976	13.8	19.5	16.8	-8.2	0.9	11.8	14.0														
1977	10.4	14.7	11.8	-9.2	-2.7	3.4	0.3	-13.5													
1978	11.9	16.0	13.6	-3.6	2.7	8.6	8.3	5.5	24.4												
1979	11.0	14.4	12.2	-2.8	2.7	7.4	6.8	4.4	13.3	2.3											
1980	9.9	12.9	10.7	-2.5	2.1	6.0	5.3	3.1	8.6	0.7	-0.9										
1981	10.4	13.2	11.2	-0.5	3.9	7.4	7.0	5.6	10.4	5.7	7.5	15.8									
1982	9.5	12.0	10.1	-0.5	3.3	6.4	5.9	4.5	8.2	4.1	4.7	7.5	-0.8								
1983	10.0	12.4	10.7	1.0	4.7	7.5	7.2	6.3	9.6	6.6	7.7	10.6	7.9	16.7							
1984	10.7	12.8	11.3	2.5	6.0	8.7	8.6	7.9	10.9	8.7	10.0	12.7	11.7	17.9	19.2						
1985	10.6	12.7	11.2	3.1	6.3	8.8	8.7	8.1	10.8	8.9	10.0	12.2	11.3	15.3	14.6	10.0					
1986	14.0	16.1	15.0	7.7	11.0	13.7	14.1	14.1	17.1	16.2	18.2	21.4	22.5	28.3	32.2	38.7	67.5				
1987	13.5	15.5	14.5	7.6	10.7	13.1	13.4	13.4	16.1	15.1	16.7	19.3	19.8	24.0	25.8	28.0	37.0	6.6			
1988	14.7	16.6	15.7	9.3	12.3	14.7	15.1	15.2	17.8	17.1	18.7	21.2	22.0	25.8	27.6	29.7	36.2	20.6	34.6		
1989	14.4	16.3	15.4	9.4	12.2	14.4	14.7	14.8	17.1	16.5	17.9	20.0	20.5	23.6	24.7	25.8	29.8	17.2	22.5	10.4	
1990	11.4	13.0	11.9	6.1	8.5	10.4	10.4	10.2	12.0	11.0	11.7	13.0	12.7	14.4	14.1	13.2	13.9	0.4	-1.6	-19.7	-49.8
1991	10.5	11.9	10.9	5.3	7.6	9.3	9.3	8.9	10.5	9.5	10.1	11.1	10.6	11.9	11.3	10.1	10.1	-1.3	-3.3	-15.9	-29.1
1992	8.9	10.2	9.1	3.7	5.8	7.3	7.2	6.7	8.1	6.9	7.3	7.9	7.2	8.0	7.1	5.6	4.9	-5.5	-7.9	-18.6	-28.2
1993	8.9	10.2	9.2	4.1	6.0	7.5	7.3	6.9	8.2	7.1	7.5	8.1	7.5	8.2	7.4	6.1	5.6	-3.2	-4.9	-12.8	-18.6
1994	8.9	10.1	9.1	4.2	6.1	7.4	7.3	7.0	8.2	7.1	7.5	8.1	7.5	8.2	7.4	6.2	5.8	-1.9	-3.1	-9.4	-13.4
1995	8.6	9.8	8.8	4.1	5.9	7.2	7.1	6.7	7.9	6.9	7.2	7.7	7.1	7.7	7.0	5.9	5.5	-1.4	-2.4	-7.7	-10.7
1996	8.1	9.2	8.3	3.8	5.5	6.7	6.5	6.2	7.2	6.2	6.5	6.9	6.3	6.9	6.1	5.0	4.6	-1.7	-2.7	-7.3	-9.9
1997	7.4	8.4	7.5	3.1	4.7	5.8	5.6	5.2	6.2	5.2	5.4	5.8	5.1	5.5	4.7	3.6	3.1	-2.8	-3.7	-8.0	-10.3
1998	6.8	7.7	6.8	2.6	4.1	5.1	4.9	4.5	5.4	4.4	4.5	4.9	4.2	4.5	3.7	2.6	2.0	-3.4	-4.3	-8.2	-10.3
1999	8.3	9.3	8.4	4.4	5.9	7.0	6.9	6.6	7.5	6.7	6.9	7.3	6.9	7.3	6.7	5.9	5.6	0.8	0.4	-2.8	-4.1
2000	7.4	8.4	7.5	3.6	5.1	6.1	5.9	5.6	6.4	5.6	5.7	6.1	5.6	5.9	5.3	4.4	4.0	-0.5	-1.0	-4.0	-5.3
2001	6.7	7.6	6.7	2.9	4.3	5.2	5.1	4.7	5.5	4.6	4.7	5.0	4.5	4.7	4.1	3.2	2.8	-1.5	-2.1	-5.0	-6.2
2002	5.9	6.7	5.8	2.1	3.4	4.3	4.1	3.7	4.4	3.6	3.6	3.8	3.3	3.5	2.8	1.9	1.4	-2.7	-3.4	-6.1	-7.3
2003	6.4	7.2	6.4	2.9	4.2	5.0	4.9	4.5	5.2	4.5	4.5	4.8	4.3	4.5	3.9	3.1	2.7	-1.1	-1.6	-4.0	-5.0
2004	6.6	7.4	6.6	3.2	4.4	5.2	5.1	4.8	5.4	4.7	4.8	5.1	4.6	4.8	4.3	3.5	3.2	-0.4	-0.8	-3.0	-3.9
2005	7.5	8.3	7.5	4.2	5.5	6.3	6.2	5.9	6.6	6.0	6.1	6.4	6.0	6.3	5.8	5.2	5.0	1.7	1.4	-0.6	-1.2
2006	7.5	8.2	7.5	4.3	5.5	6.4	6.2	6.0	6.7	6.0	6.2	6.4	6.1	6.3	5.9	5.3	5.1	1.9	1.7	-0.1	-0.7
2007	7.0	7.7	7.0	3.9	5.0	5.8	5.7	5.4	6.1	5.4	5.5	5.8	5.4	5.6	5.2	4.6	4.3	1.3	1.1	-0.7	-1.3
2008	5.4	6.1	5.4	2.3	3.4	4.1	3.9	3.6	4.2	3.5	3.5	3.7	3.2	3.4	2.9	2.2	1.8	-1.1	-1.5	-3.3	-4.0
2009	5.5	6.2	5.5	2.5	3.5	4.2	4.1	3.8	4.3	3.7	3.7	3.9	3.4	3.6	3.1	2.4	2.1	-0.7	-1.0	-2.7	-3.4
2010	5.4	6.0	5.4	2.4	3.5	4.1	4.0	3.7	4.2	3.6	3.6	3.8	3.3	3.5	3.0	2.4	2.1	-0.6	-1.0	-2.6	-3.2

Japan Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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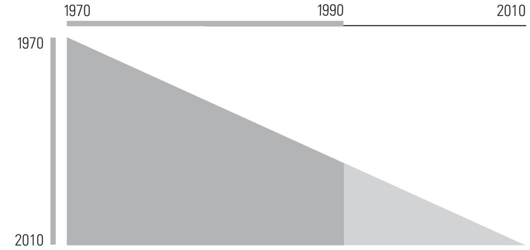
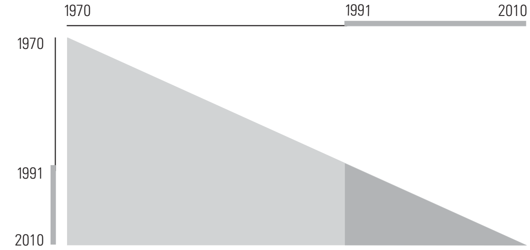
1991	-8.4																			
1992	-17.4	-26.4																		
1993	-8.2	-8.0	10.3																	
1994	-4.3	-2.9	8.8	7.3																
1995	-2.9	-1.5	6.8	5.0	2.8															
1996	-3.2	-2.1	3.9	1.8	-0.9	-4.7														
1997	-4.6	-4.0	0.5	-1.9	-5.0	-8.9	-13.2													
1998	-5.3	-4.9	-1.3	-3.6	-6.4	-9.4	-11.8	-10.4												
1999	1.0	2.2	6.3	5.6	5.3	5.9	9.4	20.7	51.9											
2000	-0.9	0.0	3.3	2.3	1.4	1.2	2.6	7.9	17.1	-17.7										
2001	-2.3	-1.7	1.1	-0.1	-1.1	-1.8	-1.2	1.8	5.9	-17.1	-16.4									
2002	-3.8	-3.4	-1.1	-2.3	-3.6	-4.5	-4.4	-2.7	-0.7	-18.3	-18.5	-20.6								
2003	-1.6	-1.0	1.3	0.4	-0.3	-0.7	-0.2	2.0	4.5	-7.3	-3.9	2.4	25.4							
2004	-0.6	0.0	2.2	1.4	0.8	0.6	1.3	3.3	5.6	-3.6	-0.1	5.4	18.4	11.4						
2005	2.0	2.7	5.0	4.5	4.3	4.4	5.5	7.8	10.4	3.5	7.7	13.7	25.2	25.1	38.8					
2006	2.3	3.0	5.1	4.7	4.5	4.7	5.6	7.7	10.0	4.0	7.6	12.4	20.7	19.1	23.0	7.2				
2007	1.5	2.1	4.0	3.6	3.3	3.4	4.1	5.8	7.6	2.1	4.9	8.5	14.3	11.5	11.6	-2.1	-11.3			
2008	-1.5	-1.1	0.5	-0.2	-0.7	-1.0	-0.7	0.5	1.6	-4.0	-2.3	-0.3	3.1	-1.3	-4.5	-19.0	-32.0	-52.8		
2009	-0.9	-0.5	1.0	0.4	-0.1	-0.3	0.1	1.2	2.2	-2.7	-1.1	0.9	3.9	0.4	-1.8	-12.0	-18.4	-21.9	8.9	
2010	-0.9	-0.5	1.0	0.4	0.0	-0.2	0.1	1.2	2.1	-2.4	-0.9	0.9	3.5	0.4	-1.4	-9.5	-13.6	-14.4	4.8	0.7

Netherlands Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-14.6																				
1971	-15.3	-16.0																			
1972	-3.1	2.7	21.3																		
1973	-8.4	-6.3	-1.4	-24.2																	
1974	-13.6	-13.4	-12.5	-29.5	-34.7																
1975	-2.6	-0.2	3.8	-2.1	8.9	52.6															
1976	-2.5	-0.4	2.7	-2.0	5.4	25.5	-1.7														
1977	-2.2	-0.5	2.1	-1.7	3.9	16.8	-1.1	-0.6													
1978	-2.3	-0.8	1.4	-2.0	2.5	11.8	-1.8	-1.9	-3.2												
1979	-1.4	0.0	2.0	-0.7	3.2	10.8	0.3	1.0	1.8	6.8											
1980	0.3	1.8	3.8	1.6	5.3	11.9	3.8	5.2	7.1	12.3	17.7										
1981	-0.6	0.6	2.3	0.2	3.2	8.7	1.3	1.9	2.6	4.5	3.3	-11.1									
1982	0.5	1.7	3.3	1.5	4.4	9.3	3.1	3.9	4.8	6.8	6.8	1.4	13.8								
1983	4.2	5.6	7.4	6.2	9.2	14.1	9.3	10.8	12.7	15.9	18.2	18.4	33.1	52.4							
1984	5.3	6.7	8.5	7.4	10.3	14.8	10.6	12.1	13.9	16.8	18.8	19.0	29.1	36.7	21.0						
1985	6.1	7.5	9.2	8.2	10.9	15.1	11.3	12.8	14.5	17.0	18.7	18.9	26.4	30.6	19.7	18.3					
1986	6.1	7.4	9.0	8.1	10.6	14.3	10.9	12.1	13.5	15.6	16.9	16.7	22.3	24.4	15.1	12.1	6.0				
1987	4.7	5.9	7.2	6.3	8.5	11.8	8.4	9.3	10.3	11.8	12.5	11.7	15.5	15.8	6.7	1.9	-6.3	-18.5			
1988	5.7	6.9	8.2	7.4	9.5	12.7	9.6	10.5	11.5	13.0	13.7	13.2	16.7	17.2	10.1	7.4	3.7	2.6	23.7		
1989	6.7	7.8	9.1	8.4	10.4	13.4	10.6	11.6	12.6	14.0	14.8	14.4	17.6	18.2	12.5	10.7	8.8	9.8	23.9	24.1	
1990	5.3	6.3	7.5	6.7	8.5	11.3	8.5	9.2	10.0	11.1	11.5	10.8	13.3	13.2	7.6	5.4	2.8	2.0	8.8	1.4	-21.4
1991	5.6	6.6	7.7	7.0	8.7	11.3	8.7	9.4	10.1	11.1	11.5	10.9	13.1	13.1	8.2	6.3	4.3	4.0	9.6	4.9	-4.8
1992	5.4	6.3	7.4	6.7	8.3	10.7	8.3	8.9	9.5	10.4	10.7	10.1	12.1	11.9	7.4	5.7	3.9	3.5	7.9	4.0	-2.7
1993	6.8	7.8	8.8	8.2	9.9	12.2	10.0	10.7	11.4	12.3	12.7	12.3	14.3	14.3	10.5	9.4	8.2	8.6	13.1	10.9	7.6
1994	6.3	7.2	8.2	7.6	9.1	11.3	9.2	9.8	10.4	11.2	11.5	11.1	12.8	12.7	9.1	7.9	6.7	6.8	10.4	8.2	5.0
1995	6.5	7.4	8.4	7.8	9.3	11.3	9.3	9.9	10.4	11.2	11.5	11.1	12.7	12.6	9.3	8.2	7.2	7.4	10.6	8.7	6.1
1996	7.5	8.4	9.3	8.8	10.3	12.3	10.4	11.0	11.6	12.4	12.8	12.4	14.0	14.0	11.1	10.3	9.5	9.9	13.0	11.7	9.9
1997	8.7	9.5	10.5	10.1	11.5	13.5	11.7	12.4	13.0	13.9	14.3	14.1	15.7	15.8	13.2	12.6	12.1	12.6	15.8	14.9	13.7
1998	8.7	9.5	10.5	10.1	11.4	13.4	11.7	12.3	12.9	13.7	14.0	13.8	15.3	15.4	12.9	12.4	11.9	12.4	15.2	14.4	13.3
1999	9.1	10.0	10.9	10.5	11.8	13.7	12.1	12.7	13.3	14.1	14.4	14.3	15.7	15.8	13.5	13.0	12.6	13.1	15.7	15.0	14.1
2000	8.8	9.5	10.4	10.0	11.3	13.1	11.5	12.0	12.6	13.3	13.6	13.4	14.7	14.8	12.5	12.0	11.6	12.0	14.3	13.6	12.6
2001	7.8	8.5	9.3	8.9	10.1	11.8	10.2	10.7	11.1	11.8	12.0	11.7	12.9	12.8	10.6	10.0	9.5	9.7	11.7	10.8	9.7
2002	6.4	7.1	7.8	7.4	8.5	10.0	8.4	8.8	9.2	9.7	9.8	9.5	10.5	10.3	8.1	7.4	6.7	6.8	8.5	7.4	6.1
2003	6.3	7.0	7.7	7.3	8.3	9.8	8.3	8.6	9.0	9.5	9.6	9.2	10.1	10.0	7.8	7.2	6.5	6.6	8.1	7.1	5.9
2004	6.2	6.8	7.5	7.1	8.1	9.5	8.0	8.3	8.7	9.1	9.2	8.9	9.7	9.6	7.5	6.8	6.2	6.3	7.7	6.7	5.5
2005	6.8	7.4	8.1	7.7	8.7	10.1	8.7	9.1	9.4	9.9	10.0	9.7	10.5	10.4	8.5	7.9	7.4	7.5	8.9	8.0	7.0
2006	7.0	7.6	8.3	7.9	8.9	10.3	8.9	9.3	9.6	10.0	10.2	9.9	10.7	10.6	8.8	8.2	7.7	7.8	9.2	8.4	7.5
2007	7.0	7.6	8.2	7.8	8.8	10.1	8.8	9.1	9.4	9.9	10.0	9.7	10.5	10.4	8.6	8.1	7.6	7.7	9.0	8.2	7.3
2008	5.5	6.1	6.7	6.3	7.1	8.4	7.0	7.3	7.5	7.9	7.9	7.6	8.3	8.1	6.3	5.7	5.1	5.1	6.2	5.3	4.4
2009	6.3	6.8	7.4	7.0	7.9	9.1	7.8	8.1	8.4	8.8	8.8	8.5	9.2	9.1	7.4	6.9	6.4	6.4	7.5	6.8	5.9
2010	6.3	6.8	7.4	7.0	7.9	9.0	7.8	8.1	8.3	8.7	8.8	8.5	9.1	9.0	7.4	6.8	6.4	6.4	7.5	6.7	5.9

Netherlands Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
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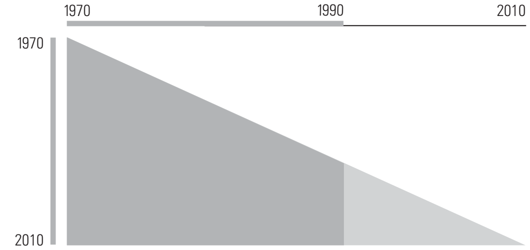
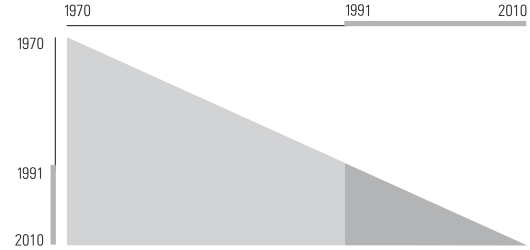
1990																				
1991	11.9																			
1992	6.6	1.3																		
1993	17.3	20.1	38.8																	
1994	11.6	11.5	16.7	-5.5																
1995	11.7	11.6	15.0	3.1	11.7															
1996	15.1	15.8	19.4	12.9	22.1	32.5														
1997	18.7	19.9	23.6	19.8	28.2	36.4	40.3													
1998	17.6	18.4	21.3	17.8	23.6	27.5	25.0	9.8												
1999	18.0	18.8	21.3	18.4	23.2	26.0	23.9	15.7	21.6											
2000	16.0	16.4	18.3	15.4	18.9	20.3	17.3	9.6	9.5	-2.5										
2001	12.5	12.6	13.8	10.7	13.0	13.2	9.4	1.6	-1.1	-12.4	-22.3									
2002	8.4	8.0	8.7	5.4	6.7	6.0	1.6	-6.1	-10.1	-20.7	-29.8	-37.3								
2003	8.0	7.6	8.2	5.2	6.4	5.7	1.8	-4.6	-7.4	-14.7	-18.7	-16.9	3.4							
2004	7.5	7.1	7.6	4.8	5.8	5.2	1.7	-3.8	-6.0	-11.6	-13.8	-11.0	2.1	0.9						
2005	8.9	8.7	9.3	6.8	7.9	7.5	4.8	0.3	-1.0	-4.8	-5.3	-1.0	11.1	15.0	29.0					
2006	9.3	9.1	9.7	7.4	8.5	8.2	5.8	1.9	1.0	-2.0	-1.9	2.2	12.0	14.9	21.9	14.9				
2007	9.0	8.9	9.4	7.3	8.2	7.9	5.7	2.3	1.4	-1.1	-0.9	2.7	10.7	12.5	16.3	10.0	5.2			
2008	5.8	5.4	5.7	3.5	4.1	3.5	1.1	-2.4	-3.7	-6.5	-7.0	-4.8	0.6	0.1	-0.1	-9.8	-22.2	-49.5		
2009	7.3	7.1	7.4	5.4	6.2	5.8	3.7	0.7	-0.2	-2.3	-2.3	0.2	5.5	5.9	6.9	1.4	-3.1	-7.3	34.9	
2010	7.3	7.0	7.3	5.5	6.2	5.8	3.9	1.1	0.4	-1.6	-1.5	0.8	5.6	5.9	6.8	2.3	-0.8	-2.8	20.5	6.1

Netherlands Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-14.6																				
1971	-10.6	-6.6																			
1972	0.4	7.9	22.4																		
1973	-3.1	0.8	4.5	-13.4																	
1974	-7.7	-5.9	-5.7	-19.8	-26.2																
1975	0.6	3.6	6.2	0.8	7.9	41.9															
1976	1.6	4.3	6.4	2.4	7.7	24.6	7.3														
1977	2.3	4.7	6.6	3.4	7.6	18.9	7.4	7.4													
1978	3.3	5.6	7.3	4.8	8.4	17.1	8.8	9.6	11.7												
1979	4.1	6.2	7.8	5.7	8.9	15.9	9.4	10.0	11.3	11.0											
1980	4.1	6.0	7.4	5.5	8.3	14.0	8.4	8.7	9.1	7.8	4.6										
1981	1.9	3.4	4.4	2.4	4.3	8.7	3.2	2.3	1.0	-2.5	-9.3	-23.1									
1982	2.2	3.6	4.5	2.8	4.6	8.4	3.6	3.0	2.1	-0.3	-4.1	-8.4	6.3								
1983	4.3	5.7	6.8	5.3	7.2	10.9	7.0	7.0	6.9	6.0	4.7	4.8	18.7	31.1							
1984	4.3	5.6	6.6	5.2	6.9	10.2	6.7	6.6	6.5	5.7	4.6	4.6	13.9	17.7	4.2						
1985	7.2	8.7	9.8	8.8	10.7	14.0	11.2	11.7	12.2	12.3	12.5	14.1	23.3	29.0	28.0	51.8					
1986	8.8	10.3	11.4	10.6	12.5	15.7	13.3	13.9	14.6	15.0	15.6	17.4	25.5	30.3	30.0	42.9	34.0				
1987	8.3	9.7	10.7	9.9	11.6	14.5	12.2	12.7	13.2	13.4	13.7	15.0	21.3	24.3	22.6	28.7	17.2	0.4			
1988	8.4	9.7	10.7	9.9	11.5	14.2	12.1	12.4	12.9	13.0	13.2	14.3	19.7	21.9	20.1	24.0	14.8	5.2	10.0		
1989	9.5	10.8	11.8	11.1	12.7	15.3	13.3	13.8	14.3	14.6	14.9	16.1	21.0	23.1	21.8	25.3	18.6	13.5	20.1	30.1	
1990	8.5	9.7	10.5	9.9	11.3	13.6	11.7	12.0	12.4	12.4	12.6	13.4	17.4	18.8	17.0	19.2	12.7	7.3	9.6	9.4	-11.3
1991	8.6	9.7	10.5	9.9	11.2	13.4	11.6	11.9	12.2	12.3	12.4	13.1	16.7	17.8	16.2	17.9	12.3	7.9	9.8	9.7	-0.5
1992	8.0	9.1	9.8	9.2	10.4	12.4	10.7	10.9	11.1	11.1	11.1	11.6	14.8	15.6	13.9	15.1	9.9	5.8	6.9	6.2	-1.8
1993	9.0	10.0	10.7	10.2	11.4	13.3	11.7	12.0	12.3	12.3	12.4	13.0	16.0	16.9	15.5	16.8	12.4	9.3	10.8	10.9	6.1
1994	8.8	9.8	10.5	10.0	11.1	13.0	11.4	11.7	11.9	11.9	12.0	12.5	15.2	16.0	14.6	15.7	11.6	8.9	10.1	10.1	6.1
1995	9.3	10.3	11.0	10.5	11.5	13.3	11.9	12.1	12.4	12.4	12.5	13.1	15.7	16.4	15.1	16.1	12.6	10.2	11.4	11.6	8.5
1996	9.8	10.7	11.4	11.0	12.0	13.8	12.4	12.7	13.0	13.0	13.1	13.7	16.1	16.8	15.7	16.7	13.5	11.5	12.7	13.0	10.6
1997	10.1	11.1	11.7	11.3	12.3	14.0	12.8	13.0	13.3	13.4	13.5	14.0	16.4	17.0	16.0	16.9	14.0	12.2	13.4	13.8	11.7
1998	10.4	11.3	12.0	11.6	12.6	14.2	13.0	13.3	13.5	13.6	13.8	14.3	16.5	17.1	16.2	17.0	14.4	12.7	13.9	14.2	12.5
1999	10.2	11.1	11.7	11.3	12.3	13.8	12.6	12.8	13.1	13.2	13.3	13.7	15.8	16.3	15.4	16.2	13.6	12.0	13.0	13.3	11.6
2000	9.6	10.4	11.0	10.6	11.5	12.9	11.8	12.0	12.2	12.2	12.2	12.6	14.5	14.9	14.0	14.6	12.1	10.6	11.3	11.5	9.8
2001	8.5	9.2	9.8	9.3	10.1	11.5	10.3	10.4	10.5	10.5	10.5	10.8	12.5	12.8	11.8	12.2	9.7	8.1	8.7	8.6	6.8
2002	7.4	8.1	8.6	8.1	8.9	10.1	9.0	9.0	9.1	9.0	8.9	9.1	10.6	10.8	9.8	10.1	7.6	6.0	6.3	6.1	4.2
2003	7.9	8.6	9.1	8.7	9.4	10.6	9.5	9.6	9.7	9.6	9.5	9.7	11.2	11.5	10.5	10.8	8.5	7.0	7.5	7.3	5.7
2004	8.0	8.6	9.1	8.7	9.4	10.6	9.5	9.6	9.6	9.6	9.5	9.7	11.1	11.3	10.4	10.7	8.6	7.1	7.5	7.4	5.9
2005	8.1	8.7	9.2	8.8	9.5	10.6	9.6	9.6	9.7	9.6	9.6	9.8	11.2	11.4	10.5	10.8	8.7	7.4	7.8	7.7	6.2
2006	8.6	9.3	9.7	9.3	10.0	11.2	10.2	10.3	10.4	10.3	10.3	10.5	11.9	12.1	11.3	11.6	9.7	8.4	8.9	8.8	7.6
2007	8.8	9.5	9.9	9.5	10.2	11.3	10.4	10.5	10.6	10.5	10.5	10.7	12.0	12.3	11.5	11.8	10.0	8.8	9.3	9.2	8.1
2008	7.3	7.8	8.2	7.8	8.4	9.5	8.5	8.5	8.6	8.4	8.4	8.5	9.7	9.8	8.9	9.1	7.3	6.1	6.3	6.2	4.9
2009	8.1	8.6	9.0	8.7	9.3	10.3	9.4	9.4	9.5	9.4	9.4	9.6	10.7	10.9	10.1	10.3	8.6	7.5	7.8	7.7	6.6
2010	7.9	8.4	8.8	8.4	9.0	10.0	9.1	9.1	9.2	9.1	9.1	9.2	10.3	10.5	9.7	9.9	8.2	7.2	7.5	7.3	6.3

Netherlands Long-Horizon Equity Risk Premia (in U.S. Dollars)



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1990																				
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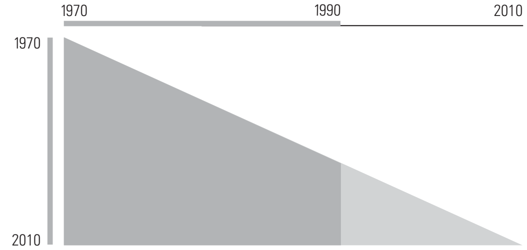
1996	14.2	15.0	19.9	16.5	21.9	22.9														
1997	15.0	15.8	19.9	17.3	21.2	21.2	19.6													
1998	15.4	16.2	19.6	17.6	20.5	20.3	19.1	18.5												
1999	14.1	14.6	17.4	15.3	17.2	16.2	14.0	11.1	3.8											
2000	11.9	12.0	14.1	11.8	12.9	11.2	8.3	4.6	-2.4	-8.6										
2001	8.4	8.2	9.6	7.1	7.3	5.0	1.4	-3.2	-10.4	-17.5	-26.3									
2002	5.5	5.1	6.1	3.4	3.1	0.5	-3.2	-7.7	-14.3	-20.3	-26.2	-26.0								
2003	7.0	6.7	7.7	5.5	5.4	3.5	0.7	-2.4	-6.6	-9.2	-9.4	-0.9	24.3							
2004	7.1	6.8	7.8	5.8	5.8	4.1	1.7	-0.8	-4.0	-5.6	-4.8	2.3	16.5	8.8						
2005	7.4	7.2	8.1	6.3	6.3	4.9	2.9	0.8	-1.8	-2.7	-1.5	4.7	15.0	10.3	11.9					
2006	8.7	8.6	9.6	8.0	8.2	7.0	5.4	3.8	2.0	1.8	3.5	9.5	18.3	16.4	20.2	28.4				
2007	9.2	9.1	10.0	8.6	8.8	7.8	6.4	5.1	3.6	3.6	5.4	10.7	18.0	16.4	19.0	22.5	16.6			
2008	5.8	5.5	6.2	4.6	4.5	3.2	1.6	-0.1	-1.9	-2.6	-1.8	1.7	6.3	2.7	1.2	-2.3	-17.7	-52.0		
2009	7.6	7.4	8.1	6.7	6.8	5.8	4.5	3.2	1.8	1.6	2.8	6.4	11.0	8.8	8.8	8.1	1.3	-6.4	39.3	
2010	7.1	7.0	7.6	6.3	6.3	5.4	4.1	2.9	1.6	1.4	2.4	5.6	9.6	7.5	7.2	6.3	0.8	-4.5	19.3	-0.7

New Zealand Long-Horizon Equity Risk Premia (in Local Currency)



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1982	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA								
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1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
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1989	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-8.4	5.8	
1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-21.7	-21.2	-48.1
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-11.3	-7.5	-14.1
1992	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-9.6	-6.4	-10.4
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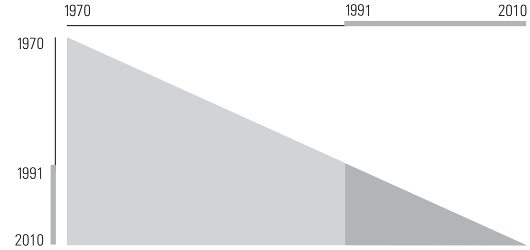
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-1.8	-0.2	-0.7
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-2.1	-0.6	-1.1
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.7	0.8	0.4
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.5	1.9	1.7
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.6	2.0	1.8
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.0	2.3	2.1
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.7	1.9	1.7
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-1.5	-0.5	-0.8
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.7	0.4	0.1
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.8	0.2	0.0

New Zealand Long-Horizon Equity Risk Premia (in Local Currency)



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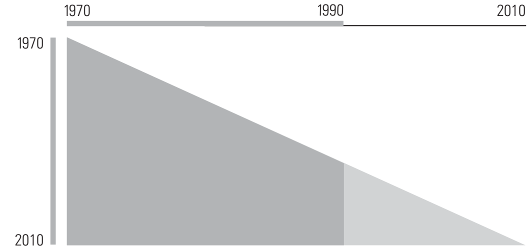
1990																				
1991	19.8																			
1992	8.5	-2.9																		
1993	22.0	23.1	49.1																	
1994	14.0	12.0	19.5	-10.1																
1995	13.5	11.9	16.8	0.7	11.4															
1996	11.6	9.9	13.1	1.2	6.8	2.2														
1997	9.7	8.1	10.3	0.6	4.1	0.5	-1.2													
1998	6.0	4.0	5.1	-3.7	-2.1	-6.5	-10.9	-20.6												
1999	6.4	4.7	5.8	-1.4	0.4	-2.4	-3.9	-5.2	10.1											
2000	3.0	1.1	1.6	-5.2	-4.4	-7.5	-9.9	-12.8	-9.0	-28.0										
2001	3.6	2.0	2.6	-3.3	-2.3	-4.6	-5.9	-7.1	-2.6	-8.9	10.2									
2002	2.8	1.3	1.7	-3.5	-2.7	-4.7	-5.9	-6.8	-3.4	-7.9	2.2	-5.9								
2003	4.2	2.9	3.4	-1.2	-0.2	-1.6	-2.2	-2.4	1.3	-0.9	8.1	7.1	20.0							
2004	5.2	4.1	4.7	0.7	1.7	0.7	0.5	0.7	4.3	3.1	10.9	11.1	19.5	19.1						
2005	5.1	4.1	4.6	0.9	1.9	0.9	0.8	1.1	4.1	3.1	9.4	9.2	14.2	11.3	3.5					
2006	5.3	4.3	4.8	1.4	2.4	1.6	1.5	1.8	4.6	3.8	9.1	8.9	12.6	10.1	5.6	7.8				
2007	4.6	3.7	4.1	0.9	1.7	0.9	0.8	1.0	3.4	2.6	7.0	6.4	8.9	6.1	1.8	0.9	-5.9			
2008	1.8	0.8	1.0	-2.2	-1.6	-2.6	-3.0	-3.2	-1.4	-2.7	0.4	-1.0	-0.1	-4.2	-10.0	-14.5	-25.6	-45.3		
2009	2.7	1.7	2.0	-1.0	-0.4	-1.2	-1.5	-1.5	0.3	-0.7	2.3	1.3	2.4	-0.6	-4.5	-6.5	-11.3	-14.0	17.3	
2010	2.4	1.4	1.7	-1.1	-0.5	-1.3	-1.6	-1.6	0.0	-1.0	1.7	0.8	1.6	-1.0	-4.3	-5.9	-9.3	-10.4	7.0	-3.3

New Zealand Long-Horizon Equity Risk Premia (in U.S. Dollars)



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1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-25.0	-24.4	-48.6
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1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.9	5.4	6.2
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.2	2.7	3.1
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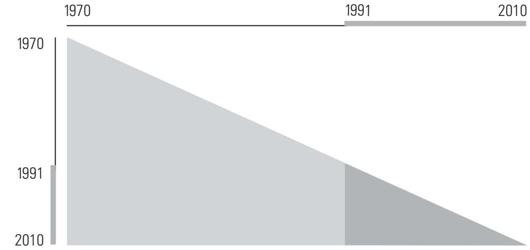
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-4.6	-2.8	-3.0
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-4.0	-2.3	-2.5
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-2.5	-0.8	-0.9
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.8	2.6	2.7
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.5	4.3	4.6
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.3	4.0	4.2
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.7	4.4	4.6
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.7	4.3	4.5
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.2	1.1	1.2
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.9	3.2	3.4
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.0	3.3	3.4

New Zealand Long-Horizon Equity Risk Premia (in U.S. Dollars)



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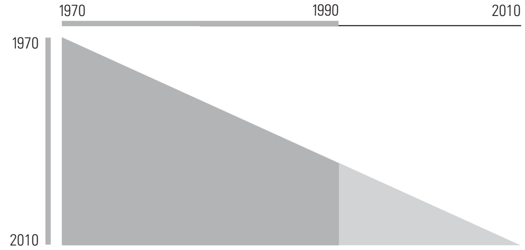
1989																				
1990																				
1991	10.0																			
1992	1.3	-7.5																		
1993	21.6	27.4	62.2																	
1994	16.9	19.2	32.5	2.8																
1995	16.2	17.8	26.2	8.2	13.7															
1996	15.3	16.3	22.3	9.0	12.1	10.5														
1997	10.5	10.5	14.1	2.1	1.9	-4.0	-18.6													
1998	5.6	5.0	7.1	-3.9	-5.6	-12.0	-23.3	-28.0												
1999	6.0	5.5	7.4	-1.8	-2.7	-6.7	-12.5	-9.5	9.1											
2000	1.5	0.6	1.6	-7.1	-8.7	-13.2	-19.1	-19.3	-14.9	-38.9										
2001	1.7	0.9	1.8	-5.7	-6.9	-10.4	-14.6	-13.6	-8.7	-17.6	3.6									
2002	3.1	2.5	3.5	-3.1	-3.8	-6.3	-9.1	-7.2	-2.0	-5.7	10.9	18.3								
2003	6.7	6.4	7.7	2.2	2.2	0.7	-0.7	2.3	8.4	8.2	23.9	34.1	49.9							
2004	8.4	8.3	9.6	4.8	5.0	4.0	3.2	6.4	12.1	12.7	25.6	32.9	40.2	30.6						
2005	7.7	7.6	8.7	4.3	4.4	3.5	2.7	5.4	10.1	10.3	20.2	24.3	26.3	14.5	-1.6					
2006	8.0	7.8	8.9	4.8	5.0	4.2	3.6	6.0	10.3	10.4	18.7	21.7	22.5	13.4	4.8	11.2				
2007	7.6	7.5	8.5	4.6	4.8	4.0	3.4	5.6	9.4	9.4	16.3	18.5	18.5	10.6	4.0	6.8	2.4			
2008	4.0	3.6	4.3	0.5	0.3	-0.7	-1.7	-0.2	2.6	1.9	7.0	7.5	5.7	-3.1	-11.5	-14.9	-27.9	-58.2		
2009	6.1	5.9	6.7	3.2	3.3	2.5	1.9	3.6	6.5	6.2	11.3	12.2	11.4	4.9	-0.2	0.1	-3.5	-6.5	45.2	
2010	6.0	5.8	6.5	3.3	3.3	2.6	2.0	3.6	6.3	6.0	10.5	11.3	10.4	4.8	0.5	0.9	-1.7	-3.1	24.4	3.7

Spain Long-Horizon Equity Risk Premia (in Local Currency)



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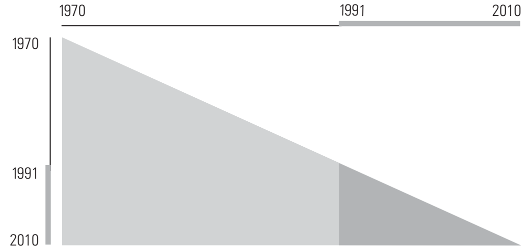
1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.0	9.8	9.8	5.8	21.1	39.7						
1985	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.8	12.4	12.9	10.7	22.5	32.6	25.4					
1986	NA	NA	NA	NA	NA	NA	NA	NA	NA	17.6	22.0	24.0	24.5	36.8	48.2	52.4	79.5				
1987	NA	NA	NA	NA	NA	NA	NA	NA	NA	15.9	19.5	20.9	20.7	29.8	36.6	35.6	40.7	1.9			
1988	NA	NA	NA	NA	NA	NA	NA	NA	NA	15.0	18.1	19.1	18.7	26.0	30.7	28.4	29.4	4.4	6.9		
1989	NA	NA	NA	NA	NA	NA	NA	NA	NA	13.0	15.6	16.3	15.6	21.4	24.5	21.5	20.5	0.9	0.4	-6.1	
1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.8	10.7	10.8	9.6	13.9	15.6	11.5	8.8	-8.9	-12.5	-22.2	-38.3
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.4	10.2	10.3	9.1	12.9	14.2	10.5	8.1	-6.2	-8.3	-13.3	-16.9
1992	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.6	8.1	7.9	6.7	9.8	10.7	7.0	4.4	-8.1	-10.1	-14.4	-17.1
1993	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.6	11.2	11.3	10.5	13.7	14.8	12.0	10.3	0.4	0.2	-1.1	0.1
1994	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.7	9.1	9.1	8.1	10.8	11.6	8.8	6.9	-2.2	-2.7	-4.3	-4.0
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.8	9.1	9.1	8.2	10.7	11.4	8.8	7.2	-0.9	-1.2	-2.4	-1.7
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.7	11.1	11.1	10.4	13.0	13.8	11.6	10.3	3.4	3.6	3.2	4.5
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.4	12.7	12.9	12.4	14.8	15.7	13.9	12.9	6.9	7.3	7.4	9.1
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	12.5	13.9	14.1	13.7	16.1	17.0	15.4	14.6	9.2	9.8	10.1	11.9
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	12.8	14.1	14.4	14.0	16.2	17.1	15.6	14.9	9.9	10.6	10.9	12.6
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.6	12.7	12.9	12.4	14.5	15.2	13.7	12.9	8.1	8.6	8.7	10.1
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.6	11.6	11.7	11.2	13.1	13.7	12.2	11.4	6.8	7.2	7.2	8.3
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.8	9.7	9.7	9.1	10.8	11.3	9.7	8.8	4.4	4.5	4.3	5.2
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.5	10.5	10.5	10.0	11.7	12.1	10.7	9.9	5.8	6.0	5.9	6.8
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.8	10.7	10.7	10.3	11.9	12.3	10.9	10.2	6.3	6.6	6.6	7.4
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.1	11.0	11.0	10.6	12.1	12.5	11.2	10.5	6.9	7.2	7.2	8.0
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.8	11.7	11.8	11.4	12.9	13.3	12.1	11.5	8.1	8.4	8.5	9.4
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.7	11.6	11.6	11.3	12.7	13.1	12.0	11.4	8.1	8.4	8.5	9.3
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.0	9.8	9.8	9.3	10.6	10.9	9.7	9.1	5.9	6.1	6.0	6.7
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.9	10.6	10.7	10.3	11.6	11.9	10.8	10.2	7.2	7.4	7.5	8.1
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.0	9.7	9.7	9.3	10.5	10.8	9.6	9.0	6.1	6.3	6.2	6.8

Spain Long-Horizon Equity Risk Premia (in Local Currency)



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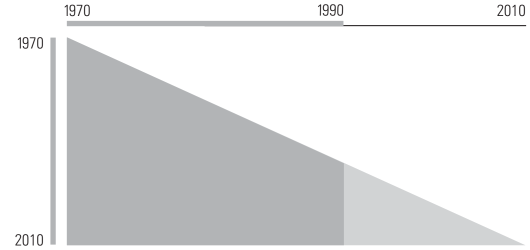
1991	4.4																			
1992	-6.6	-17.6																		
1993	12.9	17.1	51.8																	
1994	4.6	4.6	15.7	-20.3																
1995	5.6	5.9	13.7	-5.4	51.5															
1996	11.6	13.1	20.7	10.4	21.0	42.0														
1997	15.9	17.8	24.8	18.1	27.7	41.5	41.1													
1998	18.2	20.2	26.5	21.4	29.5	39.3	38.0	34.8												
1999	18.3	20.0	25.4	21.0	27.4	34.2	31.6	26.8	18.9											
2000	14.9	16.1	20.3	15.8	20.2	24.3	19.9	12.8	1.8	-15.3										
2001	12.6	13.4	16.8	12.4	15.7	18.4	13.6	6.8	-2.6	-13.3	-11.3									
2002	8.8	9.2	11.8	7.4	9.7	11.1	5.9	-1.1	-10.1	-19.8	-22.1	-32.8								
2003	10.3	10.8	13.3	9.5	11.7	13.2	9.1	3.8	-2.5	-7.8	-5.3	-2.3	28.2							
2004	10.7	11.2	13.6	10.1	12.2	13.5	10.0	5.5	0.6	-3.0	0.0	3.8	22.1	16.0						
2005	11.1	11.6	13.8	10.7	12.6	13.9	10.8	7.0	3.0	0.4	3.5	7.2	20.6	16.7	17.4					
2006	12.4	12.9	15.1	12.2	14.1	15.4	12.8	9.6	6.5	4.7	8.0	11.9	23.1	21.4	24.1	30.7				
2007	12.1	12.6	14.6	11.9	13.7	14.8	12.4	9.5	6.7	5.2	8.1	11.3	20.1	18.1	18.8	19.5	8.3			
2008	9.1	9.4	11.1	8.4	9.8	10.5	7.9	4.9	1.9	0.0	1.9	3.8	9.9	6.2	3.8	-0.8	-16.5	-41.3		
2009	10.6	10.9	12.6	10.2	11.6	12.4	10.1	7.5	5.0	3.7	5.8	7.9	13.7	11.3	10.3	8.6	1.2	-2.4	36.6	
2010	9.1	9.3	10.8	8.4	9.6	10.2	8.0	5.4	3.0	1.5	3.2	4.8	9.5	6.9	5.3	2.9	-4.0	-8.1	8.5	-19.7

Spain Long-Horizon Equity Risk Premia (in U.S. Dollars)



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1980	NA	NA	NA	NA	NA	NA	NA	NA	NA	-2.7	8.1										
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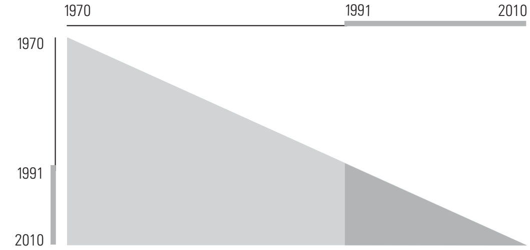
1982	NA	NA	NA	NA	NA	NA	NA	NA	NA	-1.4	2.6	-0.2	-18.8								
1983	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.6	2.6	0.7	-8.1	2.5							
1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.4	9.2	9.5	6.5	19.2	35.9						
1985	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.8	12.5	13.4	12.2	22.5	32.5	29.1					
1986	NA	NA	NA	NA	NA	NA	NA	NA	NA	19.3	24.0	26.6	28.3	40.0	52.5	60.9	92.7				
1987	NA	NA	NA	NA	NA	NA	NA	NA	NA	17.2	21.1	22.9	23.7	32.1	39.5	40.8	46.6	0.5			
1988	NA	NA	NA	NA	NA	NA	NA	NA	NA	16.3	19.6	21.0	21.4	28.1	33.2	32.5	33.6	4.1	7.7		
1989	NA	NA	NA	NA	NA	NA	NA	NA	NA	14.2	17.0	18.0	17.9	23.1	26.6	24.7	23.6	0.6	0.7	-6.4	
1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.4	11.4	11.8	11.0	14.8	16.5	13.3	10.1	-10.5	-14.2	-25.1	-43.9
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.0	10.8	11.1	10.4	13.6	15.0	12.0	9.2	-7.6	-9.6	-15.3	-19.8
1992	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.3	8.9	9.0	8.1	10.8	11.7	8.7	5.8	-8.7	-10.6	-15.1	-18.0
1993	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.6	11.2	11.4	10.9	13.6	14.7	12.3	10.2	-1.6	-1.9	-3.8	-3.2
1994	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.6	9.0	9.1	8.3	10.6	11.3	8.9	6.6	-4.1	-4.8	-6.9	-7.0
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.8	9.1	9.2	8.5	10.6	11.3	9.1	7.0	-2.5	-2.8	-4.3	-4.0
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.5	10.8	11.0	10.5	12.6	13.4	11.5	9.9	1.6	1.7	1.0	2.1
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.8	12.2	12.4	12.1	14.1	14.9	13.3	12.0	4.7	5.1	4.8	6.2
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	12.2	13.5	13.8	13.6	15.6	16.5	15.1	14.0	7.4	8.1	8.1	9.7
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.7	12.9	13.2	12.9	14.7	15.5	14.2	13.1	7.0	7.5	7.5	8.9
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.2	11.3	11.5	11.1	12.8	13.4	12.0	10.8	5.0	5.3	5.2	6.2
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.1	10.1	10.2	9.8	11.3	11.8	10.3	9.2	3.6	3.8	3.5	4.4
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.8	8.7	8.8	8.3	9.7	10.1	8.6	7.4	2.1	2.2	1.8	2.4
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.7	10.6	10.7	10.4	11.8	12.3	11.0	10.0	5.1	5.4	5.3	6.1
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.3	11.2	11.3	11.0	12.4	12.9	11.7	10.8	6.2	6.6	6.5	7.4
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.0	10.9	11.0	10.7	11.9	12.4	11.2	10.4	6.0	6.3	6.2	7.0
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.2	12.2	12.3	12.1	13.4	13.8	12.8	12.1	8.0	8.4	8.5	9.3
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.6	12.4	12.6	12.4	13.6	14.1	13.1	12.4	8.6	9.0	9.1	9.9
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.7	10.5	10.6	10.3	11.4	11.8	10.8	10.0	6.2	6.5	6.4	7.1
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.7	11.5	11.6	11.4	12.5	12.9	12.0	11.3	7.7	8.0	8.1	8.8
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.6	10.3	10.4	10.1	11.2	11.5	10.6	9.8	6.4	6.6	6.6	7.2

Spain Long-Horizon Equity Risk Premia (in U.S. Dollars)



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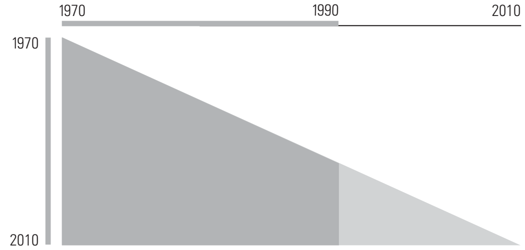
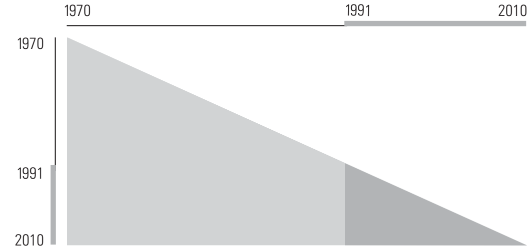
1991	4.3																			
1992	-5.1	-14.5																		
1993	10.4	13.4	41.3																	
1994	2.3	1.6	9.7	-22.0																
1995	4.0	3.9	10.0	-5.6	49.2															
1996	9.7	10.8	17.1	9.1	19.2	38.5														
1997	13.4	14.9	20.8	15.6	24.6	36.9	35.3													
1998	16.4	18.1	23.6	20.0	27.8	37.1	36.4	37.6												
1999	14.7	16.0	20.4	16.9	22.6	28.2	24.8	19.5	1.4											
2000	11.2	12.0	15.3	11.6	15.4	18.4	13.4	6.2	-9.6	-20.6										
2001	8.7	9.2	11.8	8.1	10.9	12.7	7.6	0.6	-11.7	-18.2	-15.9									
2002	6.3	6.5	8.6	4.9	6.9	7.9	2.8	-3.6	-14.0	-19.1	-18.3	-20.8								
2003	10.0	10.4	12.7	9.8	12.2	13.7	10.2	6.0	-0.3	-0.8	5.8	16.7	54.1							
2004	11.0	11.6	13.7	11.2	13.5	15.0	12.0	8.7	3.9	4.4	10.6	19.4	39.6	25.0						
2005	10.4	10.9	12.8	10.4	12.4	13.7	10.9	7.9	3.6	4.0	8.9	15.1	27.0	13.4	1.9					
2006	12.7	13.2	15.2	13.2	15.2	16.6	14.4	12.1	8.9	10.0	15.1	21.3	31.8	24.3	24.0	46.1				
2007	13.1	13.7	15.5	13.7	15.6	16.9	14.9	12.9	10.2	11.3	15.8	21.1	29.5	23.3	22.7	33.1	20.1			
2008	9.9	10.2	11.8	9.8	11.3	12.2	10.0	7.7	4.7	5.1	8.3	11.7	17.2	9.8	6.0	7.3	-12.1	-44.3		
2009	11.6	12.0	13.5	11.8	13.3	14.3	12.4	10.5	8.0	8.7	11.9	15.4	20.6	15.0	13.0	15.8	5.6	-1.6	41.0	
2010	9.7	10.0	11.4	9.6	10.9	11.7	9.7	7.8	5.3	5.6	8.3	10.9	14.9	9.3	6.7	7.6	-2.0	-9.4	8.1	-24.9

Spain Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	NA																				
1971	NA	NA																			
1972	NA	NA	NA																		
1973	NA	NA	NA	NA																	
1974	NA	NA	NA	NA	NA																
1975	NA	NA	NA	NA	NA	NA															
1976	NA	NA	NA	NA	NA	NA	-37.6														
1977	NA	NA	NA	NA	NA	NA	-36.9	-36.2													
1978	NA	NA	NA	NA	NA	NA	-34.3	-32.6	-29.0												
1979	NA	NA	NA	NA	NA	NA	-29.6	-26.9	-22.3	-15.6											
1980	NA	NA	NA	NA	NA	NA	-22.1	-18.2	-12.2	-3.9	7.9										
1981	NA	NA	NA	NA	NA	NA	-15.0	-10.5	-4.0	4.3	14.2	20.5									
1982	NA	NA	NA	NA	NA	NA	-16.6	-13.1	-8.4	-3.3	0.8	-2.8	-26.1								
1983	NA	NA	NA	NA	NA	NA	-14.9	-11.7	-7.6	-3.3	-0.3	-3.0	-14.8	-3.4							
1984	NA	NA	NA	NA	NA	NA	-8.7	-5.0	-0.6	4.2	8.1	8.2	4.0	19.1	41.6						
1985	NA	NA	NA	NA	NA	NA	-5.1	-1.4	2.9	7.5	11.3	12.0	9.9	21.8	34.5	27.3					
1986	NA	NA	NA	NA	NA	NA	2.9	6.9	11.7	16.8	21.5	23.7	24.4	37.0	50.4	54.8	82.4				
1987	NA	NA	NA	NA	NA	NA	2.7	6.4	10.7	15.1	18.9	20.5	20.5	29.8	38.1	36.9	41.7	1.1			
1988	NA	NA	NA	NA	NA	NA	3.2	6.6	10.5	14.4	17.7	19.0	18.8	26.2	32.2	29.8	30.6	4.7	8.3		
1989	NA	NA	NA	NA	NA	NA	2.4	5.5	9.0	12.4	15.2	16.0	15.4	21.4	25.5	22.3	21.0	0.6	0.3	-7.7	
1990	NA	NA	NA	NA	NA	NA	-0.4	2.3	5.3	8.1	10.3	10.5	9.4	13.8	16.3	12.1	9.0	-9.3	-12.8	-23.3	-38.9
1991	NA	NA	NA	NA	NA	NA	0.0	2.5	5.2	7.9	9.8	10.0	8.9	12.8	14.9	11.0	8.3	-6.5	-8.4	-13.9	-17.1
1992	NA	NA	NA	NA	NA	NA	-1.2	1.1	3.6	5.9	7.6	7.6	6.4	9.6	11.1	7.2	4.4	-8.6	-10.6	-15.3	-17.8
1993	NA	NA	NA	NA	NA	NA	1.8	4.1	6.6	9.0	10.7	11.0	10.2	13.5	15.2	12.2	10.3	0.0	-0.2	-1.9	-0.4
1994	NA	NA	NA	NA	NA	NA	0.6	2.8	5.1	7.2	8.7	8.8	7.9	10.7	12.0	9.0	7.0	-2.5	-3.0	-4.9	-4.3
1995	NA	NA	NA	NA	NA	NA	1.1	3.2	5.4	7.4	8.8	8.9	8.0	10.7	11.8	9.1	7.3	-1.0	-1.3	-2.7	-1.8
1996	NA	NA	NA	NA	NA	NA	3.2	5.2	7.4	9.4	10.9	11.1	10.4	13.0	14.3	12.0	10.6	3.4	3.7	3.1	4.7
1997	NA	NA	NA	NA	NA	NA	4.9	7.0	9.1	11.1	12.6	12.9	12.4	15.0	16.3	14.4	13.3	7.0	7.6	7.5	9.4
1998	NA	NA	NA	NA	NA	NA	6.3	8.3	10.4	12.4	13.9	14.2	13.8	16.3	17.6	15.9	15.0	9.4	10.2	10.4	12.4
1999	NA	NA	NA	NA	NA	NA	6.9	8.8	10.9	12.8	14.2	14.5	14.2	16.5	17.8	16.2	15.4	10.3	11.0	11.3	13.2
2000	NA	NA	NA	NA	NA	NA	6.0	7.8	9.8	11.5	12.8	13.1	12.7	14.8	15.9	14.3	13.4	8.5	9.1	9.1	10.7
2001	NA	NA	NA	NA	NA	NA	5.4	7.1	8.9	10.6	11.8	12.0	11.5	13.5	14.4	12.8	11.9	7.2	7.7	7.6	8.9
2002	NA	NA	NA	NA	NA	NA	4.0	5.6	7.3	8.8	9.9	10.0	9.5	11.3	12.0	10.4	9.4	4.8	5.1	4.8	5.8
2003	NA	NA	NA	NA	NA	NA	5.0	6.6	8.2	9.7	10.7	10.9	10.4	12.2	12.9	11.4	10.5	6.3	6.7	6.5	7.6
2004	NA	NA	NA	NA	NA	NA	5.4	7.0	8.6	10.0	11.0	11.2	10.8	12.4	13.2	11.8	10.9	7.0	7.3	7.3	8.3
2005	NA	NA	NA	NA	NA	NA	5.9	7.4	8.9	10.3	11.3	11.5	11.1	12.7	13.4	12.1	11.3	7.6	8.0	7.9	8.9
2006	NA	NA	NA	NA	NA	NA	6.7	8.2	9.7	11.1	12.1	12.2	11.9	13.5	14.2	13.0	12.3	8.8	9.2	9.2	10.2
2007	NA	NA	NA	NA	NA	NA	6.7	8.2	9.6	11.0	11.9	12.1	11.8	13.3	14.0	12.8	12.1	8.7	9.1	9.2	10.1
2008	NA	NA	NA	NA	NA	NA	5.3	6.6	8.0	9.2	10.1	10.2	9.8	11.2	11.8	10.5	9.8	6.5	6.7	6.7	7.4
2009	NA	NA	NA	NA	NA	NA	6.3	7.6	9.0	10.2	11.1	11.2	10.9	12.2	12.8	11.7	11.0	7.9	8.2	8.2	9.0
2010	NA	NA	NA	NA	NA	NA	5.6	6.9	8.2	9.4	10.2	10.2	9.9	11.2	11.7	10.6	9.9	6.9	7.1	7.1	7.8

Spain Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
1971																				
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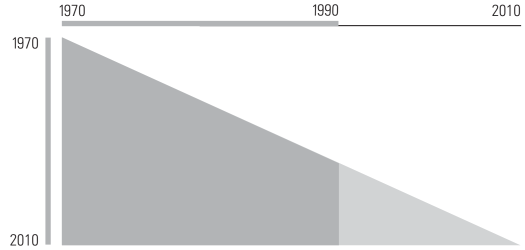
1989																				
1990																				
1991	4.8																			
1992	-7.3	-19.3																		
1993	12.5	16.3	51.9																	
1994	4.4	4.2	16.0	-19.9																
1995	5.6	5.8	14.2	-4.7	54.2															
1996	11.9	13.4	21.6	11.4	21.8	43.7														
1997	16.3	18.2	25.8	19.2	28.7	43.1	42.6													
1998	18.8	20.8	27.5	22.6	30.6	40.7	39.3	36.0												
1999	19.0	20.7	26.4	22.2	28.5	35.6	33.0	28.2	20.3											
2000	15.6	16.8	21.3	17.0	21.3	25.6	21.1	13.9	2.9	-14.5										
2001	13.3	14.1	17.8	13.6	16.8	19.6	14.8	7.9	-1.5	-12.4	-10.3									
2002	9.5	10.0	12.9	8.6	10.8	12.4	7.1	0.1	-8.9	-18.7	-20.8	-31.3								
2003	11.1	11.7	14.5	10.7	13.0	14.6	10.4	5.1	-1.1	-6.5	-3.8	-0.5	30.2							
2004	11.6	12.1	14.8	11.4	13.5	15.0	11.4	6.9	2.1	-1.6	1.7	5.6	24.1	18.0						
2005	12.1	12.6	15.1	12.0	14.0	15.3	12.2	8.4	4.5	1.8	5.1	8.9	22.3	18.4	18.7					
2006	13.3	13.9	16.2	13.5	15.4	16.8	14.1	10.9	7.8	6.0	9.4	13.4	24.5	22.6	24.9	31.1				
2007	13.0	13.5	15.7	13.1	14.8	16.1	13.6	10.7	7.9	6.3	9.3	12.5	21.3	19.0	19.4	19.7	8.3			
2008	10.0	10.3	12.2	9.5	10.9	11.7	9.0	6.0	3.0	1.0	3.0	4.9	10.9	7.1	4.3	-0.5	-16.3	-40.9		
2009	11.5	11.9	13.8	11.4	12.8	13.7	11.4	8.8	6.3	4.9	7.0	9.2	15.0	12.5	11.3	9.5	2.3	-0.7	39.4	
2010	10.1	10.4	12.0	9.7	10.9	11.6	9.3	6.8	4.3	2.9	4.6	6.3	11.0	8.2	6.6	4.2	-2.6	-6.2	11.1	-17.2

Spain Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
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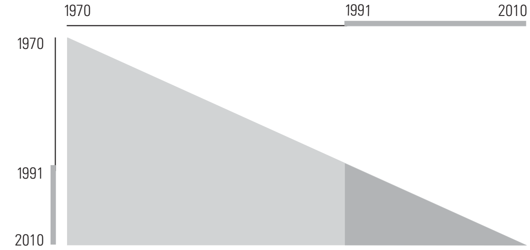
1971	NA	NA																			
1972	NA	NA	NA																		
1973	NA	NA	NA	NA																	
1974	NA	NA	NA	NA	NA																
1975	NA	NA	NA	NA	NA	NA															
1976	NA	NA	NA	NA	NA	NA	-33.0														
1977	NA	NA	NA	NA	NA	NA	-31.8	-30.6													
1978	NA	NA	NA	NA	NA	NA	-32.4	-32.2	-33.7												
1979	NA	NA	NA	NA	NA	NA	-28.4	-26.8	-24.9	-16.2											
1980	NA	NA	NA	NA	NA	NA	-21.4	-18.5	-14.4	-4.8	6.6										
1981	NA	NA	NA	NA	NA	NA	-14.9	-11.3	-6.5	2.6	12.0	17.4									
1982	NA	NA	NA	NA	NA	NA	-15.6	-12.7	-9.1	-3.0	1.4	-1.2	-19.8								
1983	NA	NA	NA	NA	NA	NA	-13.9	-11.2	-8.0	-2.8	0.5	-1.5	-11.0	-2.2							
1984	NA	NA	NA	NA	NA	NA	-8.2	-5.1	-1.5	3.9	7.9	8.2	5.2	17.7	37.6						
1985	NA	NA	NA	NA	NA	NA	-4.3	-1.1	2.6	7.8	11.8	12.8	11.7	22.2	34.4	31.2					
1986	NA	NA	NA	NA	NA	NA	4.9	8.6	13.0	18.8	23.8	26.7	28.6	40.7	55.0	63.6	96.0				
1987	NA	NA	NA	NA	NA	NA	4.4	7.8	11.7	16.7	20.8	22.8	23.7	32.4	41.1	42.3	47.8	-0.4			
1988	NA	NA	NA	NA	NA	NA	4.8	7.9	11.4	15.9	19.5	21.1	21.6	28.5	34.7	34.0	34.9	4.3	9.0		
1989	NA	NA	NA	NA	NA	NA	3.9	6.7	9.8	13.8	16.7	17.9	17.9	23.3	27.6	25.6	24.2	0.2	0.5	-8.0	
1990	NA	NA	NA	NA	NA	NA	0.6	3.0	5.6	8.9	11.2	11.6	11.0	14.8	17.3	13.9	10.4	-11.0	-14.5	-26.3	-44.7
1991	NA	NA	NA	NA	NA	NA	0.9	3.1	5.5	8.6	10.6	11.0	10.3	13.7	15.7	12.6	9.4	-7.9	-9.7	-16.0	-20.0
1992	NA	NA	NA	NA	NA	NA	-0.1	1.9	4.1	6.8	8.6	8.7	8.0	10.7	12.2	9.0	5.8	-9.2	-11.0	-16.0	-18.7
1993	NA	NA	NA	NA	NA	NA	2.2	4.3	6.4	9.1	10.9	11.3	10.7	13.5	15.1	12.6	10.3	-2.0	-2.3	-4.5	-3.7
1994	NA	NA	NA	NA	NA	NA	0.9	2.8	4.8	7.2	8.8	8.9	8.3	10.6	11.8	9.2	6.7	-4.4	-5.0	-7.4	-7.2
1995	NA	NA	NA	NA	NA	NA	1.5	3.3	5.2	7.5	8.9	9.1	8.5	10.7	11.8	9.4	7.2	-2.6	-2.9	-4.6	-4.1
1996	NA	NA	NA	NA	NA	NA	3.3	5.1	7.0	9.3	10.8	11.0	10.6	12.8	13.9	12.0	10.2	1.6	1.9	1.0	2.2
1997	NA	NA	NA	NA	NA	NA	4.8	6.6	8.5	10.7	12.2	12.5	12.2	14.4	15.6	13.9	12.4	4.8	5.3	4.9	6.5
1998	NA	NA	NA	NA	NA	NA	6.3	8.1	9.9	12.1	13.6	14.0	13.8	15.9	17.1	15.6	14.5	7.7	8.4	8.3	10.1
1999	NA	NA	NA	NA	NA	NA	6.7	8.5	10.2	12.3	13.7	14.1	13.9	15.9	17.1	15.7	14.6	8.3	9.0	9.0	10.8
2000	NA	NA	NA	NA	NA	NA	5.9	7.5	9.2	11.2	12.5	12.8	12.5	14.3	15.3	13.9	12.7	6.8	7.3	7.2	8.6
2001	NA	NA	NA	NA	NA	NA	5.3	6.9	8.4	10.3	11.5	11.7	11.4	13.0	13.9	12.5	11.3	5.7	6.1	5.9	7.1
2002	NA	NA	NA	NA	NA	NA	3.8	5.2	6.6	8.3	9.4	9.5	9.1	10.6	11.2	9.8	8.5	3.0	3.3	2.8	3.7
2003	NA	NA	NA	NA	NA	NA	4.9	6.4	7.8	9.4	10.5	10.7	10.4	11.8	12.5	11.2	10.1	5.0	5.3	5.1	6.0
2004	NA	NA	NA	NA	NA	NA	5.4	6.8	8.2	9.8	10.9	11.0	10.8	12.1	12.8	11.6	10.6	5.8	6.2	6.0	6.9
2005	NA	NA	NA	NA	NA	NA	5.8	7.1	8.5	10.0	11.0	11.2	11.0	12.3	13.0	11.8	10.8	6.3	6.7	6.6	7.5
2006	NA	NA	NA	NA	NA	NA	6.7	8.1	9.4	10.9	11.9	12.1	11.9	13.2	13.9	12.8	12.0	7.8	8.2	8.2	9.1
2007	NA	NA	NA	NA	NA	NA	6.8	8.1	9.4	10.9	11.8	12.0	11.8	13.1	13.7	12.7	11.9	7.9	8.3	8.2	9.1
2008	NA	NA	NA	NA	NA	NA	5.4	6.6	7.8	9.2	10.1	10.2	9.9	11.1	11.6	10.5	9.6	5.7	6.0	5.8	6.6
2009	NA	NA	NA	NA	NA	NA	6.5	7.7	8.9	10.2	11.1	11.3	11.1	12.2	12.8	11.8	11.0	7.3	7.6	7.5	8.3
2010	NA	NA	NA	NA	NA	NA	5.8	7.0	8.1	9.4	10.2	10.4	10.1	11.2	11.7	10.7	9.9	6.3	6.6	6.5	7.2

Spain Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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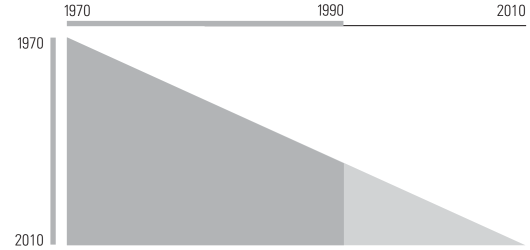
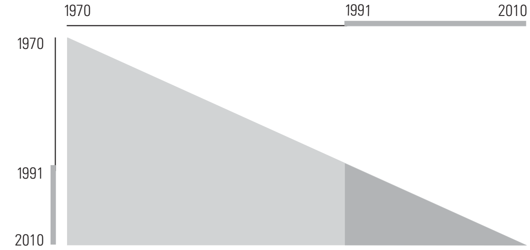
1990																				
1991	4.7																			
1992	-5.7	-16.0																		
1993	10.0	12.7	41.4																	
1994	2.1	1.3	9.9	-21.6																
1995	4.1	3.9	10.6	-4.9	51.9															
1996	10.1	11.2	17.9	10.1	20.0	40.1														
1997	13.9	15.4	21.7	16.7	25.5	38.3	36.5													
1998	17.0	18.7	24.5	21.2	28.9	38.5	37.7	38.9												
1999	16.9	18.4	23.4	20.4	26.4	33.0	30.6	27.6	16.3											
2000	13.9	14.9	18.8	15.5	19.7	23.7	19.6	13.9	1.5	-13.4										
2001	11.8	12.5	15.6	12.4	15.6	18.2	13.8	8.1	-2.2	-11.4	-9.5									
2002	7.7	8.0	10.4	6.9	9.0	10.3	5.4	-0.9	-10.8	-19.9	-23.1	-36.8								
2003	9.9	10.4	12.8	9.9	12.1	13.6	9.8	5.4	-1.3	-5.7	-3.2	0.0	36.7							
2004	10.6	11.1	13.3	10.8	12.8	14.2	11.0	7.4	2.1	-0.7	2.4	6.4	28.0	19.3						
2005	11.0	11.4	13.5	11.2	13.1	14.4	11.5	8.4	4.1	2.0	5.1	8.7	23.9	17.5	15.7					
2006	12.5	13.0	15.1	13.0	14.9	16.3	13.9	11.4	7.9	6.7	10.1	14.0	26.7	23.4	25.4	35.1				
2007	12.3	12.8	14.7	12.8	14.5	15.7	13.5	11.2	8.1	7.1	10.0	13.3	23.3	19.9	20.1	22.3	9.5			
2008	9.4	9.7	11.3	9.3	10.6	11.5	9.1	6.6	3.4	1.9	3.8	5.7	12.8	8.0	5.2	1.7	-15.0	-39.5		
2009	11.1	11.5	13.1	11.3	12.7	13.6	11.6	9.5	6.8	5.9	8.0	10.2	16.9	13.6	12.5	11.6	3.8	1.0	41.4	
2010	9.7	10.0	11.5	9.7	10.9	11.6	9.6	7.5	4.9	3.9	5.6	7.3	12.8	9.4	7.7	6.1	-1.1	-4.7	12.8	-15.9

Switzerland Long-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-18.8																				
1971	-4.4	10.1																			
1972	3.4	14.5	18.9																		
1973	-3.0	2.3	-1.6	-22.0																	
1974	-10.0	-7.8	-13.8	-30.1	-38.3																
1975	-1.8	1.5	-0.6	-7.1	0.4	39.0															
1976	-1.9	0.9	-0.9	-5.9	-0.5	18.4	-2.2														
1977	-1.5	1.0	-0.6	-4.4	-0.1	12.7	-0.5	1.2													
1978	-1.9	0.2	-1.2	-4.5	-1.0	8.3	-1.9	-1.8	-4.9												
1979	-1.0	1.0	-0.1	-2.9	0.3	8.0	0.3	1.1	1.1	7.1											
1980	-1.0	0.7	-0.3	-2.7	0.1	6.4	-0.1	0.5	0.2	2.7	-1.6										
1981	-2.1	-0.5	-1.6	-3.9	-1.6	3.6	-2.3	-2.3	-3.2	-2.6	-7.5	-13.4									
1982	-1.2	0.3	-0.6	-2.5	-0.4	4.4	-0.6	-0.3	-0.6	0.4	-1.8	-1.9	9.7								
1983	0.8	2.3	1.6	0.1	2.3	6.8	2.7	3.4	3.8	5.5	5.2	7.4	17.8	25.9							
1984	0.8	2.2	1.6	0.2	2.2	6.2	2.6	3.2	3.4	4.8	4.4	5.9	12.3	13.6	1.2						
1985	4.6	6.1	5.8	4.8	7.1	11.2	8.4	9.6	10.6	12.8	13.8	16.9	24.4	29.3	31.0	60.8					
1986	4.4	5.8	5.5	4.6	6.6	10.3	7.7	8.7	9.6	11.4	12.0	14.2	19.8	22.3	21.1	31.0	1.2				
1987	2.3	3.5	3.1	2.1	3.8	7.0	4.4	5.0	5.3	6.5	6.4	7.6	11.0	11.3	7.7	9.8	-15.7	-32.5			
1988	3.3	4.6	4.2	3.3	5.0	8.1	5.7	6.4	6.9	8.0	8.1	9.4	12.6	13.1	10.5	12.8	-3.1	-5.3	21.9		
1989	4.5	5.7	5.4	4.6	6.3	9.3	7.2	7.9	8.4	9.6	9.9	11.2	14.2	14.9	13.0	15.4	4.1	5.0	23.8	25.7	
1990	2.9	4.0	3.7	2.9	4.3	7.0	4.8	5.3	5.7	6.5	6.5	7.3	9.6	9.6	7.2	8.2	-2.3	-3.1	6.7	-0.9	-27.6
1991	3.6	4.7	4.4	3.6	5.1	7.6	5.7	6.2	6.5	7.4	7.4	8.3	10.4	10.5	8.6	9.6	1.1	1.1	9.5	5.4	-4.8
1992	4.4	5.4	5.2	4.5	5.9	8.4	6.5	7.1	7.5	8.4	8.5	9.3	11.4	11.5	9.9	11.0	3.9	4.4	11.8	9.2	3.7
1993	6.0	7.1	6.9	6.4	7.8	10.2	8.6	9.2	9.7	10.7	11.0	11.9	14.1	14.5	13.3	14.6	8.9	10.0	17.1	16.1	13.7
1994	5.2	6.2	6.1	5.5	6.8	9.1	7.5	8.0	8.4	9.3	9.4	10.2	12.0	12.2	10.9	11.9	6.5	7.1	12.8	11.3	8.4
1995	5.9	6.9	6.8	6.2	7.5	9.7	8.2	8.8	9.2	10.0	10.2	11.0	12.8	13.0	11.9	12.9	8.1	8.9	14.0	12.9	10.8
1996	6.3	7.3	7.1	6.7	7.9	10.0	8.6	9.2	9.6	10.4	10.6	11.3	13.0	13.2	12.2	13.2	8.8	9.6	14.3	13.3	11.5
1997	8.0	9.0	8.9	8.5	9.8	11.9	10.7	11.3	11.8	12.7	13.0	13.8	15.5	15.9	15.2	16.3	12.6	13.6	18.2	17.8	16.8
1998	8.2	9.2	9.1	8.7	10.0	12.0	10.8	11.4	11.9	12.7	13.0	13.8	15.4	15.8	15.1	16.1	12.7	13.6	17.8	17.4	16.5
1999	8.1	9.0	9.0	8.6	9.8	11.7	10.6	11.2	11.6	12.4	12.7	13.4	14.9	15.2	14.5	15.4	12.2	13.0	16.8	16.4	15.4
2000	8.0	8.9	8.8	8.5	9.6	11.4	10.3	10.9	11.3	12.0	12.2	12.9	14.3	14.6	13.9	14.7	11.6	12.4	15.8	15.3	14.4
2001	7.0	7.9	7.8	7.4	8.4	10.2	9.1	9.5	9.9	10.5	10.7	11.2	12.5	12.6	11.9	12.5	9.5	10.1	13.1	12.4	11.3
2002	6.0	6.7	6.6	6.2	7.2	8.8	7.7	8.1	8.3	8.9	9.0	9.4	10.5	10.6	9.8	10.2	7.3	7.7	10.3	9.5	8.3
2003	6.3	7.1	7.0	6.6	7.5	9.1	8.1	8.4	8.7	9.3	9.4	9.8	10.9	10.9	10.2	10.7	7.9	8.3	10.8	10.1	9.0
2004	6.2	7.0	6.9	6.5	7.4	8.9	7.9	8.3	8.5	9.0	9.1	9.6	10.6	10.6	9.9	10.3	7.6	8.0	10.4	9.7	8.6
2005	7.0	7.7	7.7	7.3	8.2	9.7	8.8	9.1	9.4	9.9	10.1	10.5	11.5	11.6	10.9	11.4	8.9	9.4	11.7	11.1	10.2
2006	7.2	8.0	7.9	7.6	8.5	9.9	9.0	9.4	9.7	10.2	10.3	10.8	11.7	11.8	11.2	11.6	9.3	9.7	11.9	11.4	10.5
2007	6.9	7.6	7.6	7.2	8.1	9.5	8.6	8.9	9.2	9.7	9.8	10.2	11.1	11.2	10.5	10.9	8.7	9.0	11.1	10.5	9.7
2008	5.8	6.5	6.4	6.0	6.8	8.1	7.2	7.5	7.7	8.1	8.2	8.5	9.3	9.3	8.6	8.9	6.7	6.9	8.8	8.2	7.2
2009	6.2	6.8	6.7	6.4	7.2	8.5	7.6	7.9	8.1	8.5	8.6	8.9	9.7	9.7	9.1	9.4	7.3	7.5	9.4	8.8	7.9
2010	6.0	6.7	6.6	6.2	7.0	8.3	7.4	7.7	7.9	8.3	8.3	8.6	9.4	9.4	8.8	9.1	7.0	7.2	9.0	8.4	7.5

Switzerland Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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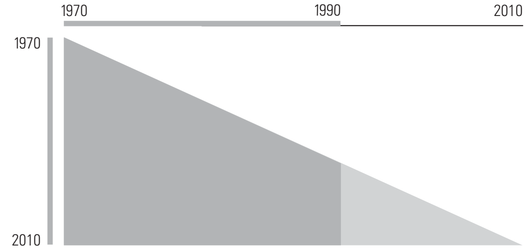
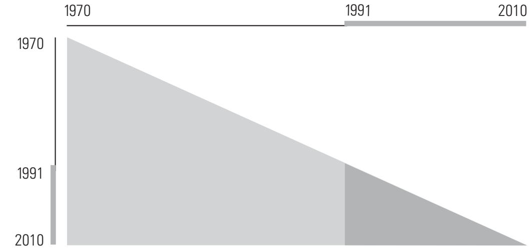
1991	18.0																			
1992	19.4	20.8																		
1993	27.4	32.2	43.6																	
1994	17.4	17.2	15.4	-12.7																
1995	18.5	18.6	17.8	5.0	22.7															
1996	18.1	18.1	17.4	8.7	19.4	16.1														
1997	23.2	24.0	24.7	20.0	30.9	35.0	53.9													
1998	22.0	22.6	22.9	18.7	26.6	27.9	33.8	13.7												
1999	20.2	20.5	20.5	16.6	22.5	22.4	24.5	9.9	6.0											
2000	18.6	18.6	18.4	14.8	19.4	18.7	19.4	7.9	4.9	3.9										
2001	14.8	14.5	13.8	10.1	13.4	11.8	11.0	0.3	-4.2	-9.4	-22.6									
2002	11.2	10.6	9.6	5.8	8.2	6.1	4.4	-5.5	-10.3	-15.7	-25.5	-28.4								
2003	11.8	11.3	10.4	7.1	9.3	7.6	6.4	-1.5	-4.6	-7.2	-10.9	-5.1	18.2							
2004	11.2	10.7	9.8	6.8	8.7	7.1	6.0	-0.8	-3.2	-5.1	-7.3	-2.2	10.8	3.5						
2005	12.7	12.3	11.6	9.0	11.0	9.8	9.1	3.5	2.0	1.4	0.9	6.7	18.4	18.6	33.6					
2006	12.9	12.6	12.0	9.6	11.4	10.4	9.8	4.9	3.8	3.5	3.5	8.7	17.9	17.8	25.0	16.4				
2007	11.9	11.5	10.9	8.6	10.2	9.2	8.5	4.0	2.9	2.5	2.3	6.5	13.5	12.3	15.2	6.0	-4.4			
2008	9.2	8.7	7.9	5.5	6.8	5.6	4.7	0.3	-1.1	-1.9	-2.6	0.3	5.0	2.4	2.1	-8.4	-20.8	-37.1		
2009	9.8	9.3	8.7	6.5	7.7	6.7	6.0	2.0	0.9	0.4	0.0	2.8	7.3	5.5	5.9	-1.1	-6.9	-8.2	20.8	
2010	9.3	8.8	8.2	6.1	7.3	6.2	5.5	1.8	0.8	0.4	0.0	2.5	6.4	4.7	4.9	-0.9	-5.2	-5.4	10.4	0.1

Switzerland Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-18.8																				
1971	1.3	21.4																			
1972	8.6	22.4	23.3																		
1973	4.2	11.8	7.0	-9.3																	
1974	-0.9	3.6	-2.4	-15.2	-21.2																
1975	5.1	9.8	6.9	1.5	6.8	34.8															
1976	5.0	9.0	6.5	2.3	6.1	19.7	4.6														
1977	7.4	11.1	9.4	6.6	10.5	21.1	14.3	23.9													
1978	8.5	11.9	10.5	8.4	11.9	20.2	15.3	20.7	17.5												
1979	8.6	11.7	10.4	8.6	11.6	18.1	14.0	17.1	13.6	9.8											
1980	6.8	9.3	8.0	6.0	8.2	13.1	8.8	9.8	5.1	-1.0	-11.8										
1981	4.9	7.1	5.7	3.7	5.3	9.1	4.8	4.9	0.1	-5.7	-13.5	-15.1									
1982	4.5	6.4	5.0	3.2	4.6	7.8	4.0	3.9	-0.2	-4.6	-9.3	-8.1	-1.1								
1983	5.2	7.1	5.9	4.3	5.7	8.6	5.4	5.5	2.4	-0.6	-3.2	-0.3	7.1	15.2							
1984	3.9	5.5	4.3	2.7	3.8	6.3	3.2	3.0	0.0	-2.9	-5.5	-3.9	-0.2	0.3	-14.7						
1985	9.9	11.8	11.2	10.2	11.8	14.9	12.9	13.8	12.5	11.8	12.1	16.9	24.9	33.6	42.8	100.2					
1986	11.1	12.9	12.4	11.6	13.2	16.1	14.4	15.3	14.4	14.0	14.6	19.0	25.8	32.5	38.3	64.8	29.4				
1987	9.7	11.4	10.7	9.9	11.3	13.8	12.0	12.7	11.6	10.9	11.1	14.3	19.2	23.3	25.3	38.6	7.8	-13.7			
1988	9.3	10.9	10.3	9.5	10.7	13.0	11.3	11.9	10.8	10.1	10.2	12.9	16.9	19.9	20.9	29.7	6.2	-5.3	3.1		
1989	10.0	11.5	11.0	10.2	11.5	13.6	12.1	12.7	11.8	11.2	11.4	14.0	17.6	20.3	21.1	28.3	10.3	3.9	12.7	22.4	
1990	8.9	10.3	9.7	9.0	10.1	12.0	10.5	10.9	9.9	9.3	9.2	11.3	14.3	16.2	16.3	21.5	5.8	-0.2	4.4	5.0	-12.4
1991	9.0	10.3	9.8	9.1	10.1	11.9	10.5	10.9	10.0	9.4	9.4	11.3	13.9	15.6	15.6	20.0	6.6	2.0	6.0	7.0	-0.8
1992	9.1	10.4	9.9	9.2	10.2	11.9	10.6	11.0	10.1	9.6	9.6	11.3	13.7	15.2	15.2	18.9	7.3	3.7	7.1	8.2	3.4
1993	10.5	11.8	11.3	10.8	11.8	13.5	12.3	12.8	12.1	11.7	11.8	13.7	16.1	17.6	17.9	21.5	11.6	9.1	12.9	14.9	13.0
1994	10.0	11.2	10.8	10.2	11.2	12.8	11.6	12.0	11.3	10.9	11.0	12.6	14.8	16.1	16.2	19.2	10.2	7.8	10.9	12.2	10.2
1995	11.2	12.4	12.0	11.5	12.4	14.0	13.0	13.4	12.9	12.6	12.8	14.4	16.5	17.9	18.1	21.0	13.1	11.3	14.5	16.1	15.0
1996	10.7	11.9	11.5	11.0	11.9	13.4	12.4	12.8	12.2	11.9	12.0	13.5	15.4	16.6	16.7	19.3	11.9	10.2	12.8	14.1	12.9
1997	11.8	13.0	12.6	12.2	13.1	14.6	13.7	14.1	13.6	13.4	13.6	15.1	17.0	18.2	18.4	21.0	14.4	13.0	15.7	17.1	16.4
1998	12.1	13.3	13.0	12.6	13.4	14.9	14.0	14.4	14.0	13.8	14.0	15.4	17.2	18.4	18.6	21.0	14.9	13.7	16.2	17.5	16.9
1999	11.5	12.5	12.2	11.8	12.6	13.9	13.1	13.4	12.9	12.7	12.9	14.2	15.8	16.8	16.9	19.0	13.2	12.0	14.1	15.1	14.4
2000	11.2	12.2	11.9	11.4	12.2	13.5	12.6	13.0	12.5	12.3	12.4	13.6	15.1	16.0	16.1	18.0	12.5	11.3	13.2	14.1	13.3
2001	10.0	11.0	10.6	10.2	10.9	12.1	11.2	11.5	10.9	10.7	10.7	11.8	13.1	13.9	13.8	15.5	10.2	8.9	10.5	11.1	10.1
2002	9.3	10.2	9.8	9.4	10.0	11.1	10.3	10.5	9.9	9.6	9.6	10.6	11.8	12.5	12.3	13.8	8.7	7.5	8.9	9.3	8.3
2003	10.0	10.8	10.5	10.1	10.7	11.8	11.0	11.3	10.8	10.5	10.5	11.5	12.7	13.4	13.3	14.8	10.0	8.9	10.3	10.8	9.9
2004	10.1	10.9	10.6	10.2	10.8	11.9	11.1	11.3	10.8	10.6	10.6	11.6	12.7	13.3	13.3	14.7	10.2	9.1	10.4	10.9	10.1
2005	10.2	11.0	10.7	10.4	11.0	12.0	11.2	11.5	11.0	10.8	10.8	11.7	12.9	13.5	13.4	14.7	10.4	9.4	10.7	11.2	10.5
2006	10.6	11.4	11.2	10.8	11.4	12.4	11.7	11.9	11.5	11.3	11.4	12.3	13.4	14.0	13.9	15.2	11.2	10.2	11.5	12.0	11.4
2007	10.4	11.2	10.9	10.6	11.2	12.1	11.4	11.6	11.2	11.0	11.1	11.9	13.0	13.5	13.4	14.7	10.8	9.9	11.1	11.5	10.9
2008	9.3	10.0	9.7	9.4	9.9	10.8	10.1	10.2	9.8	9.5	9.5	10.3	11.2	11.7	11.6	12.7	8.9	7.9	9.0	9.3	8.6
2009	9.7	10.4	10.1	9.8	10.3	11.2	10.5	10.7	10.3	10.0	10.0	10.8	11.7	12.2	12.1	13.1	9.5	8.7	9.7	10.0	9.4
2010	9.7	10.4	10.1	9.8	10.3	11.2	10.5	10.7	10.3	10.1	10.1	10.8	11.7	12.1	12.0	13.1	9.6	8.7	9.7	10.0	9.4

Switzerland Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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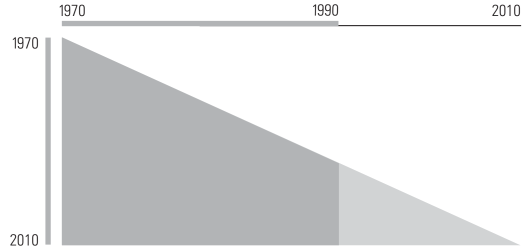
1991	10.8																			
1992	11.3	11.8																		
1993	21.4	26.7	41.7																	
1994	15.8	17.5	20.4	-0.9																
1995	20.5	22.9	26.6	19.1	39.1															
1996	17.1	18.3	20.0	12.7	19.6	0.0														
1997	20.5	22.1	24.2	19.8	26.7	20.5	41.0													
1998	20.6	22.0	23.7	20.1	25.3	20.7	31.1	21.1												
1999	17.3	18.1	19.1	15.3	18.5	13.4	17.8	6.2	-8.6											
2000	15.9	16.4	17.0	13.5	15.9	11.2	14.0	5.0	-3.0	2.7										
2001	12.2	12.3	12.4	8.7	10.1	5.2	6.3	-2.4	-10.3	-11.1	-24.8									
2002	10.0	9.9	9.7	6.2	7.1	2.5	2.9	-4.7	-11.2	-12.0	-19.4	-14.0								
2003	11.7	11.7	11.7	8.7	9.8	6.1	7.0	1.3	-2.6	-1.1	-2.4	8.8	31.6							
2004	11.7	11.8	11.8	9.1	10.1	6.8	7.7	2.9	-0.1	1.6	1.4	10.1	22.1	12.6						
2005	12.0	12.1	12.1	9.6	10.6	7.8	8.6	4.6	2.2	4.0	4.3	11.5	20.1	14.3	15.9					
2006	12.8	13.0	13.1	10.9	11.8	9.4	10.3	6.9	5.1	7.1	7.8	14.3	21.4	18.0	20.7	25.5				
2007	12.3	12.3	12.4	10.3	11.1	8.8	9.6	6.5	4.9	6.5	7.1	12.4	17.7	14.2	14.7	14.1	2.8			
2008	9.7	9.7	9.5	7.4	8.0	5.6	6.1	2.9	1.0	2.1	2.1	5.9	9.2	4.7	2.7	-1.6	-15.2	-33.2		
2009	10.5	10.5	10.4	8.5	9.1	6.9	7.5	4.7	3.2	4.4	4.5	8.2	11.4	8.0	7.1	4.9	-2.0	-4.4	24.5	
2010	10.5	10.5	10.4	8.6	9.2	7.2	7.7	5.1	3.8	5.0	5.2	8.5	11.3	8.4	7.7	6.1	1.2	0.7	17.7	10.9

Switzerland Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	NA																				
1971	NA	NA																			
1972	NA	NA	NA																		
1973	NA	NA	NA	NA																	
1974	NA	NA	NA	NA	NA																
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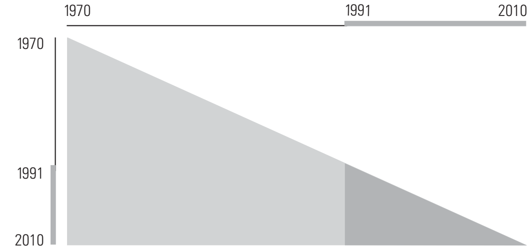
1981	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-16.2									
1982	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-2.9	10.4								
1983	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.2	18.8	27.3							
1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.9	13.3	14.8	2.3						
1985	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17.0	25.3	30.3	31.8	61.3					
1986	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	14.5	20.6	23.2	21.8	31.6	1.9				
1987	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.9	11.9	12.2	8.4	10.5	-14.9	-31.7			
1988	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.8	13.5	14.0	11.4	13.7	-2.2	-4.3	23.1		
1989	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.4	14.8	15.4	13.5	15.7	4.3	5.1	23.5	23.8	
1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.2	9.8	9.7	7.2	8.1	-2.6	-3.7	5.6	-3.1	-30.1
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.0	10.5	10.5	8.4	9.2	0.6	0.3	8.3	3.3	-6.9
1992	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.0	11.2	11.3	9.5	10.5	3.2	3.4	10.4	7.2	1.7
1993	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.6	13.9	14.2	12.9	14.1	8.2	9.1	15.9	14.5	12.2
1994	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.9	11.9	12.0	10.6	11.5	6.0	6.5	11.9	10.0	7.3
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.9	12.8	13.0	11.8	12.7	7.8	8.5	13.5	12.1	10.1
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.3	13.2	13.4	12.3	13.1	8.8	9.4	14.0	12.9	11.3
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	14.0	15.8	16.2	15.4	16.4	12.7	13.7	18.2	17.6	16.9
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	14.0	15.8	16.2	15.4	16.4	12.9	13.8	17.9	17.4	16.7
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13.7	15.4	15.7	14.9	15.8	12.5	13.3	17.1	16.5	15.8
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13.3	14.8	15.1	14.3	15.1	12.0	12.7	16.2	15.6	14.8
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.6	13.0	13.1	12.3	12.9	9.9	10.4	13.4	12.7	11.8
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.9	11.1	11.1	10.3	10.7	7.8	8.1	10.8	9.9	8.8
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.3	11.5	11.6	10.8	11.3	8.5	8.9	11.4	10.6	9.7
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.2	11.3	11.3	10.6	11.0	8.4	8.7	11.1	10.3	9.4
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.2	12.3	12.4	11.7	12.1	9.7	10.1	12.4	11.8	11.0
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.4	12.5	12.6	11.9	12.4	10.1	10.5	12.7	12.1	11.4
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.8	11.9	11.9	11.3	11.7	9.4	9.8	11.9	11.3	10.6
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.2	10.1	10.1	9.4	9.7	7.5	7.7	9.6	8.9	8.1
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.7	10.6	10.6	9.9	10.3	8.1	8.4	10.2	9.6	8.9
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.4	10.3	10.3	9.6	9.9	7.9	8.1	9.8	9.2	8.5

Switzerland Short-Horizon Equity Risk Premia (in Local Currency)



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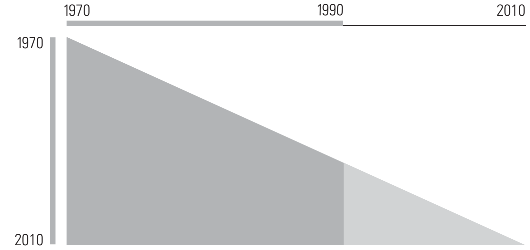
1991	16.3																			
1992	17.6	19.0																		
1993	26.2	31.2	43.5																	
1994	16.6	16.7	15.6	-12.3																
1995	18.2	18.7	18.6	6.1	24.5															
1996	18.2	18.6	18.5	10.2	21.4	18.3														
1997	23.6	24.8	26.0	21.6	32.9	37.1	55.8													
1998	22.6	23.5	24.2	20.4	28.5	29.9	35.7	15.5												
1999	20.9	21.5	21.9	18.3	24.4	24.3	26.4	11.6	7.7											
2000	19.3	19.6	19.7	16.3	21.1	20.4	21.0	9.3	6.3	4.8										
2001	15.6	15.5	15.1	11.6	15.0	13.4	12.4	1.5	-3.1	-8.6	-22.0									
2002	12.1	11.7	11.0	7.4	9.8	7.7	6.0	-4.0	-8.9	-14.4	-24.0	-26.1								
2003	12.7	12.4	11.9	8.7	11.0	9.3	8.1	0.1	-3.0	-5.7	-9.2	-2.7	20.6							
2004	12.3	11.9	11.4	8.4	10.5	9.0	7.8	0.9	-1.5	-3.3	-5.4	0.2	13.3	6.0						
2005	13.8	13.6	13.2	10.7	12.7	11.6	10.8	5.2	3.7	3.1	2.7	8.9	20.5	20.5	35.1					
2006	14.0	13.9	13.5	11.2	13.1	12.1	11.5	6.6	5.5	5.1	5.2	10.6	19.8	19.5	26.3	17.5				
2007	13.0	12.8	12.3	10.1	11.8	10.8	10.1	5.5	4.4	4.0	3.9	8.2	15.1	13.7	16.2	6.8	-3.8			
2008	10.3	9.9	9.4	7.1	8.5	7.2	6.3	1.8	0.4	-0.4	-1.0	2.0	6.6	3.9	3.3	-7.3	-19.6	-35.4		
2009	10.9	10.6	10.2	8.1	9.4	8.4	7.6	3.6	2.5	2.0	1.6	4.6	9.0	7.0	7.3	0.3	-5.4	-6.2	23.0	
2010	10.5	10.2	9.7	7.7	8.9	7.9	7.2	3.4	2.4	1.9	1.7	4.3	8.1	6.3	6.3	0.6	-3.6	-3.6	12.4	1.7

Switzerland Short-Horizon Equity Risk Premia (in U.S. Dollars)



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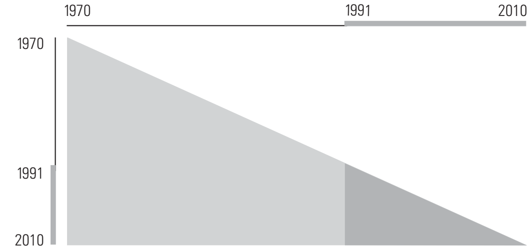
1980	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA										
1981	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-15.8									
1982	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	-3.2	9.4								
1983	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.2	17.2	25.0							
1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.1	12.1	13.4	1.9						
1985	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	19.3	28.1	34.4	39.1	76.3					
1986	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	16.5	23.0	26.4	26.9	39.4	2.5				
1987	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.4	12.4	13.0	10.0	12.7	-19.0	-40.5			
1988	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.8	13.4	14.1	11.9	14.4	-6.2	-10.5	19.6		
1989	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	11.3	14.7	15.4	13.8	16.2	1.2	0.7	21.4	23.2	
1990	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.5	9.0	8.9	6.6	7.4	-6.4	-8.6	2.1	-6.6	-36.4
1991	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7.3	9.6	9.6	7.7	8.6	-2.7	-3.8	5.4	0.7	-10.6
1992	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.2	10.3	10.4	8.8	9.7	0.2	-0.2	7.8	4.9	-1.2
1993	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.8	13.0	13.4	12.2	13.4	5.5	5.9	13.7	12.5	9.8
1994	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.1	11.0	11.1	9.8	10.6	3.3	3.5	9.7	8.1	5.1
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.3	12.2	12.4	11.3	12.2	5.8	6.2	12.0	10.9	8.9
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.6	12.4	12.6	11.7	12.5	6.7	7.1	12.4	11.5	9.8
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13.0	14.8	15.2	14.5	15.5	10.4	11.1	16.3	15.9	15.0
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13.2	14.9	15.3	14.6	15.5	10.9	11.6	16.3	16.0	15.2
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	12.9	14.5	14.8	14.1	15.0	10.6	11.2	15.5	15.1	14.3
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	12.5	14.0	14.2	13.6	14.3	10.2	10.7	14.7	14.3	13.5
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.9	12.2	12.3	11.6	12.2	8.2	8.6	12.1	11.5	10.6
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.9	10.1	10.2	9.4	9.8	5.9	6.1	9.2	8.5	7.3
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.6	10.7	10.8	10.1	10.5	6.8	7.1	10.1	9.4	8.5
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.4	10.5	10.6	9.9	10.3	6.8	7.1	9.9	9.3	8.3
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.3	11.4	11.4	10.8	11.2	8.0	8.3	11.0	10.5	9.7
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.6	11.7	11.7	11.2	11.6	8.5	8.8	11.4	11.0	10.2
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.1	11.0	11.1	10.5	10.9	7.9	8.2	10.6	10.2	9.4
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.3	9.2	9.2	8.6	8.9	6.0	6.1	8.3	7.8	7.0
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.9	9.8	9.8	9.2	9.5	6.7	6.9	9.0	8.5	7.8
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.6	9.5	9.5	8.9	9.2	6.5	6.7	8.7	8.2	7.5

Switzerland Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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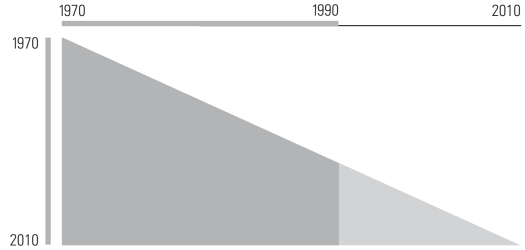
1991	15.3																			
1992	16.4	17.5																		
1993	25.3	30.2	42.9																	
1994	15.5	15.5	14.5	-13.9																
1995	17.9	18.6	18.9	6.9	27.8															
1996	17.6	18.0	18.1	9.9	21.8	15.7														
1997	22.4	23.5	24.7	20.2	31.6	33.5	51.2													
1998	21.6	22.5	23.4	19.5	27.8	27.8	33.8	16.5												
1999	20.0	20.5	21.0	17.3	23.6	22.5	24.8	11.6	6.7											
2000	18.4	18.8	19.0	15.5	20.4	19.0	19.8	9.3	5.7	4.8										
2001	14.8	14.8	14.5	10.9	14.5	12.2	11.6	1.6	-3.3	-8.3	-21.4									
2002	11.0	10.6	9.9	6.2	8.7	6.0	4.4	-4.9	-10.3	-16.0	-26.3	-31.3								
2003	11.9	11.6	11.1	7.9	10.3	8.1	7.1	-0.3	-3.7	-6.2	-9.9	-4.2	22.9							
2004	11.5	11.2	10.7	7.8	9.9	8.0	7.0	0.7	-2.0	-3.7	-5.8	-0.6	14.7	6.5						
2005	12.8	12.6	12.2	9.7	11.8	10.2	9.6	4.4	2.7	2.0	1.4	7.1	19.9	18.5	30.4					
2006	13.2	13.0	12.7	10.4	12.4	11.0	10.5	6.0	4.7	4.4	4.3	9.5	19.7	18.6	24.6	18.8				
2007	12.1	11.9	11.6	9.3	11.1	9.7	9.2	5.0	3.7	3.3	3.1	7.2	14.9	12.9	15.1	7.4	-4.1			
2008	9.4	9.0	8.5	6.2	7.6	6.1	5.3	1.1	-0.4	-1.2	-2.0	0.8	6.2	2.8	1.9	-7.6	-20.9	-37.6		
2009	10.1	9.8	9.4	7.3	8.7	7.3	6.7	3.0	1.8	1.3	0.9	3.7	8.7	6.3	6.2	0.2	-6.0	-7.0	23.7	
2010	9.7	9.4	9.0	7.0	8.3	7.0	6.4	2.9	1.8	1.3	1.0	3.5	7.8	5.7	5.5	0.5	-4.0	-4.0	12.8	1.9

U.K. Long-Horizon Equity Risk Premia (in Local Currency)



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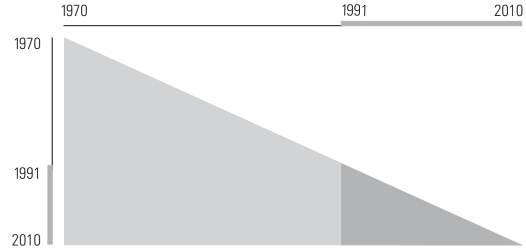
1970	-14.9																				
1971	7.5	29.8																			
1972	6.6	17.3	4.8																		
1973	-3.8	-0.1	-15.1	-35.0																	
1974	-15.8	-16.0	-31.3	-49.4	-63.8																
1975	9.1	13.9	10.0	11.7	35.0	133.8															
1976	6.3	9.8	5.8	6.1	19.7	61.5	-10.8														
1977	8.8	12.2	9.2	10.1	21.4	49.8	7.8	26.3													
1978	7.4	10.2	7.3	7.8	16.3	36.3	3.9	11.2	-3.9												
1979	6.5	8.9	6.2	6.4	13.3	28.7	2.5	6.9	-2.8	-1.6											
1980	7.5	9.7	7.5	7.8	13.9	26.8	5.5	9.5	3.9	7.8	17.3										
1981	6.7	8.7	6.6	6.8	12.0	22.8	4.3	7.4	2.6	4.8	8.0	-1.2									
1982	7.2	9.1	7.2	7.4	12.1	21.6	5.6	8.4	4.8	6.9	9.8	6.0	13.3								
1983	8.1	9.9	8.2	8.5	12.9	21.4	7.4	9.9	7.2	9.4	12.2	10.5	16.4	19.5							
1984	9.0	10.7	9.2	9.6	13.7	21.4	8.9	11.4	9.2	11.4	14.1	13.2	18.1	20.5	21.4						
1985	9.2	10.8	9.4	9.8	13.5	20.6	9.2	11.5	9.6	11.5	13.7	13.0	16.6	17.7	16.8	12.1					
1986	9.5	11.0	9.7	10.1	13.5	20.0	9.6	11.7	10.1	11.8	13.7	13.1	16.0	16.7	15.8	12.9	13.7				
1987	8.7	10.1	8.8	9.1	12.3	18.1	8.5	10.2	8.6	10.0	11.5	10.6	12.6	12.5	10.7	7.2	4.7	-4.3			
1988	8.2	9.5	8.3	8.5	11.4	16.8	7.8	9.4	7.8	9.0	10.2	9.3	10.8	10.4	8.6	5.4	3.1	-2.2	0.0		
1989	9.1	10.4	9.3	9.6	12.4	17.5	9.2	10.7	9.4	10.6	11.8	11.2	12.8	12.7	11.6	9.6	9.0	7.4	13.3	26.5	
1990	7.8	9.0	7.9	8.0	10.6	15.2	7.3	8.6	7.3	8.2	9.1	8.3	9.3	8.8	7.3	4.9	3.5	0.9	2.7	4.0	-18.4
1991	7.9	9.0	7.9	8.1	10.5	14.9	7.4	8.6	7.4	8.3	9.1	8.3	9.3	8.8	7.5	5.5	4.4	2.6	4.3	5.7	-4.7
1992	7.9	9.0	8.0	8.2	10.4	14.5	7.5	8.7	7.5	8.3	9.1	8.4	9.3	8.9	7.7	6.0	5.1	3.7	5.3	6.6	-0.1
1993	8.4	9.4	8.5	8.7	10.9	14.8	8.2	9.3	8.2	9.0	9.8	9.2	10.1	9.8	8.9	7.5	6.9	5.9	7.6	9.1	4.8
1994	7.5	8.5	7.5	7.7	9.7	13.4	7.0	8.0	6.9	7.6	8.2	7.6	8.3	7.9	6.8	5.3	4.6	3.4	4.6	5.3	1.1
1995	7.8	8.7	7.8	7.9	9.9	13.4	7.4	8.3	7.3	8.0	8.6	8.0	8.7	8.3	7.4	6.1	5.5	4.6	5.7	6.5	3.2
1996	7.8	8.6	7.8	7.9	9.8	13.1	7.4	8.3	7.3	8.0	8.5	8.0	8.6	8.3	7.4	6.2	5.7	4.9	5.9	6.7	3.8
1997	8.2	9.1	8.3	8.4	10.2	13.4	8.0	8.9	8.0	8.6	9.2	8.7	9.3	9.1	8.3	7.3	6.9	6.3	7.3	8.2	5.9
1998	8.3	9.1	8.3	8.5	10.2	13.3	8.1	8.9	8.1	8.7	9.2	8.8	9.4	9.1	8.4	7.5	7.2	6.6	7.6	8.4	6.4
1999	8.4	9.2	8.5	8.6	10.3	13.2	8.2	9.0	8.2	8.8	9.3	8.9	9.5	9.3	8.6	7.8	7.5	7.0	7.9	8.6	6.9
2000	7.8	8.6	7.8	7.9	9.5	12.3	7.5	8.2	7.5	8.0	8.4	8.0	8.5	8.2	7.5	6.7	6.3	5.8	6.6	7.1	5.3
2001	7.0	7.7	7.0	7.1	8.6	11.3	6.5	7.2	6.4	6.9	7.3	6.8	7.2	6.9	6.2	5.3	4.9	4.3	4.9	5.3	3.5
2002	6.0	6.6	5.9	5.9	7.3	9.8	5.3	5.9	5.1	5.4	5.7	5.2	5.5	5.1	4.4	3.4	2.9	2.2	2.7	2.9	1.1
2003	6.2	6.8	6.1	6.2	7.5	10.0	5.6	6.2	5.4	5.8	6.1	5.6	5.9	5.6	4.9	4.0	3.5	2.9	3.4	3.6	2.0
2004	6.2	6.8	6.1	6.2	7.5	9.9	5.6	6.2	5.5	5.8	6.1	5.6	5.9	5.6	4.9	4.1	3.7	3.1	3.6	3.8	2.3
2005	6.5	7.1	6.4	6.5	7.8	10.1	5.9	6.5	5.8	6.2	6.5	6.0	6.3	6.0	5.4	4.7	4.3	3.8	4.3	4.5	3.1
2006	6.6	7.2	6.5	6.6	7.8	10.1	6.1	6.6	6.0	6.3	6.6	6.2	6.5	6.2	5.6	4.9	4.6	4.1	4.6	4.8	3.5
2007	6.5	7.0	6.4	6.4	7.7	9.8	6.0	6.5	5.8	6.2	6.4	6.0	6.3	6.0	5.5	4.8	4.5	4.0	4.4	4.7	3.5
2008	5.4	6.0	5.3	5.3	6.5	8.6	4.8	5.3	4.6	4.9	5.1	4.6	4.9	4.5	3.9	3.2	2.8	2.3	2.6	2.8	1.5
2009	5.9	6.4	5.8	5.9	7.0	9.0	5.3	5.8	5.2	5.5	5.7	5.3	5.5	5.3	4.7	4.0	3.7	3.3	3.6	3.8	2.7
2010	6.0	6.5	5.9	5.9	7.0	9.0	5.4	5.9	5.3	5.6	5.8	5.4	5.7	5.4	4.9	4.2	3.9	3.5	3.8	4.0	2.9

U.K. Long-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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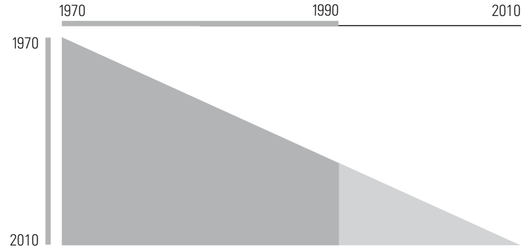
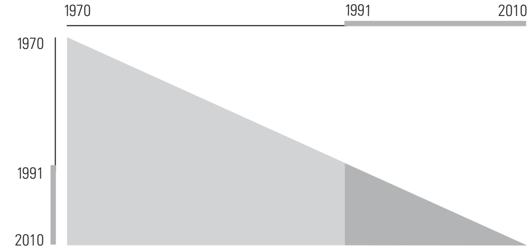
1991	9.1																			
1992	9.1	9.2																		
1993	12.5	14.2	19.3																	
1994	6.0	4.9	2.8	-13.7																
1995	7.5	7.1	6.4	-0.1	13.6															
1996	7.6	7.3	6.8	2.6	10.8	7.9														
1997	9.3	9.4	9.4	7.0	13.8	14.0	20.0													
1998	9.5	9.5	9.6	7.6	12.9	12.7	15.1	10.3												
1999	9.7	9.7	9.8	8.3	12.6	12.4	13.9	10.9	11.4											
2000	7.7	7.6	7.4	5.7	8.9	7.9	7.9	3.9	0.8	-9.9										
2001	5.5	5.1	4.7	2.9	5.2	3.8	3.0	-1.2	-5.1	-13.3	-16.7									
2002	2.7	2.1	1.4	-0.6	1.0	-0.8	-2.2	-6.7	-10.9	-18.3	-22.5	-28.3								
2003	3.6	3.1	2.6	0.9	2.5	1.1	0.1	-3.2	-5.9	-10.2	-10.3	-7.0	14.3							
2004	3.8	3.4	2.9	1.4	2.9	1.7	0.9	-1.8	-3.8	-6.8	-6.1	-2.5	10.4	6.5						
2005	4.6	4.2	3.9	2.6	4.1	3.1	2.6	0.4	-1.0	-3.1	-1.7	2.0	12.1	11.0	15.6					
2006	4.9	4.6	4.3	3.2	4.6	3.8	3.3	1.5	0.4	-1.2	0.3	3.7	11.7	10.8	12.9	10.3				
2007	4.7	4.5	4.2	3.1	4.4	3.6	3.2	1.5	0.6	-0.8	0.5	3.4	9.7	8.6	9.2	6.1	1.9			
2008	2.6	2.3	1.8	0.7	1.7	0.8	0.2	-1.6	-2.8	-4.4	-3.7	-1.8	2.6	0.2	-1.4	-7.0	-15.6	-33.1		
2009	3.8	3.5	3.1	2.1	3.2	2.4	2.0	0.5	-0.4	-1.5	-0.6	1.4	5.7	4.2	3.8	0.8	-2.4	-4.5	24.2	
2010	4.0	3.7	3.4	2.5	3.5	2.8	2.5	1.1	0.4	-0.6	0.3	2.2	6.0	4.8	4.5	2.3	0.3	-0.2	16.3	8.5

U.K. Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-15.2																				
1971	11.6	38.4																			
1972	6.6	17.4	-3.6																		
1973	-4.0	-0.3	-19.6	-35.7																	
1974	-15.9	-16.0	-34.2	-49.5	-63.4																
1975	3.7	7.4	-0.3	0.8	19.0	101.4															
1976	-0.4	2.1	-5.2	-5.6	4.4	38.2	-24.9														
1977	4.8	7.7	2.5	3.8	13.6	39.3	8.2	41.4													
1978	4.6	7.0	2.5	3.6	11.4	30.1	6.3	22.0	2.5												
1979	4.9	7.1	3.2	4.1	10.8	25.6	6.6	17.2	5.0	7.6											
1980	6.8	9.0	5.7	6.8	12.9	25.6	10.5	19.3	12.0	16.7	25.8										
1981	4.5	6.2	3.0	3.7	8.7	19.0	5.2	11.3	3.7	4.1	2.4	-21.0									
1982	3.8	5.4	2.4	3.0	7.3	16.1	3.9	8.7	2.2	2.1	0.2	-12.5	-4.1								
1983	4.0	5.5	2.8	3.4	7.3	15.1	4.3	8.5	3.0	3.1	2.0	-5.9	1.6	7.3							
1984	3.6	4.9	2.3	2.8	6.3	13.3	3.5	7.0	2.1	2.1	1.0	-5.2	0.0	2.1	-3.2						
1985	5.8	7.2	5.0	5.7	9.1	15.7	7.1	10.7	6.9	7.5	7.5	3.8	10.0	14.7	18.4	40.1					
1986	6.4	7.8	5.8	6.4	9.7	15.7	8.0	11.2	7.9	8.6	8.7	5.9	11.2	15.1	17.6	28.1	16.0				
1987	7.3	8.6	6.7	7.4	10.5	16.2	9.1	12.2	9.2	10.0	10.3	8.1	12.9	16.3	18.6	25.8	18.7	21.4			
1988	6.7	7.9	6.1	6.7	9.6	14.8	8.1	10.9	8.1	8.7	8.8	6.7	10.6	13.1	14.2	18.5	11.4	9.0	-3.3		
1989	7.0	8.2	6.5	7.1	9.8	14.7	8.5	11.0	8.5	9.0	9.2	7.3	10.9	13.0	14.0	17.4	11.8	10.3	4.8	12.9	
1990	6.6	7.7	6.0	6.6	9.1	13.6	7.7	10.1	7.7	8.1	8.1	6.4	9.4	11.1	11.6	14.1	8.9	7.1	2.4	5.2	-2.4
1991	6.5	7.6	6.0	6.5	8.9	13.1	7.6	9.8	7.5	7.9	7.9	6.3	9.0	10.5	10.9	12.9	8.4	6.8	3.2	5.4	1.6
1992	5.7	6.7	5.2	5.6	7.8	11.8	6.5	8.4	6.2	6.5	6.4	4.8	7.2	8.3	8.4	9.8	5.5	3.8	0.2	1.1	-2.8
1993	6.2	7.1	5.7	6.1	8.2	12.0	7.0	8.9	6.9	7.2	7.1	5.7	7.9	9.0	9.2	10.6	6.9	5.6	3.0	4.2	2.0
1994	5.6	6.5	5.1	5.5	7.4	11.0	6.2	7.9	6.0	6.2	6.1	4.7	6.7	7.6	7.6	8.7	5.2	3.8	1.3	2.1	-0.1
1995	5.9	6.7	5.4	5.8	7.7	11.0	6.5	8.2	6.3	6.6	6.5	5.2	7.1	8.0	8.0	9.0	5.9	4.8	2.7	3.6	2.0
1996	6.4	7.2	5.9	6.3	8.2	11.4	7.1	8.7	7.0	7.3	7.2	6.1	7.9	8.7	8.9	9.9	7.1	6.2	4.5	5.5	4.5
1997	6.7	7.5	6.3	6.7	8.5	11.6	7.5	9.1	7.4	7.7	7.7	6.6	8.4	9.2	9.3	10.3	7.8	7.1	5.6	6.6	5.9
1998	6.8	7.6	6.5	6.9	8.6	11.6	7.7	9.1	7.6	7.9	7.9	6.9	8.5	9.3	9.4	10.3	8.1	7.4	6.1	7.1	6.4
1999	6.9	7.7	6.6	6.9	8.6	11.4	7.7	9.1	7.6	7.9	7.9	7.0	8.5	9.3	9.4	10.2	8.1	7.5	6.3	7.2	6.6
2000	6.1	6.8	5.7	6.1	7.6	10.4	6.7	8.0	6.6	6.8	6.7	5.8	7.2	7.8	7.8	8.5	6.4	5.7	4.5	5.2	4.5
2001	5.3	6.0	4.9	5.2	6.7	9.3	5.7	7.0	5.5	5.7	5.6	4.6	5.9	6.4	6.4	6.9	4.9	4.1	2.9	3.3	2.6
2002	4.6	5.2	4.1	4.4	5.7	8.2	4.8	5.9	4.5	4.6	4.4	3.5	4.6	5.1	4.9	5.4	3.3	2.6	1.3	1.6	0.8
2003	5.2	5.8	4.8	5.1	6.4	8.8	5.5	6.7	5.3	5.4	5.4	4.5	5.6	6.1	6.0	6.5	4.6	4.0	2.9	3.3	2.6
2004	5.5	6.1	5.1	5.4	6.7	9.0	5.8	6.9	5.7	5.8	5.7	4.9	6.0	6.5	6.4	6.9	5.2	4.6	3.6	4.0	3.4
2005	5.4	6.0	5.1	5.3	6.6	8.9	5.8	6.8	5.6	5.7	5.6	4.8	5.9	6.3	6.3	6.8	5.1	4.5	3.6	4.0	3.4
2006	6.0	6.6	5.6	5.9	7.2	9.4	6.4	7.5	6.3	6.4	6.4	5.6	6.7	7.1	7.1	7.6	6.1	5.6	4.7	5.2	4.7
2007	5.9	6.5	5.6	5.8	7.1	9.2	6.3	7.3	6.2	6.3	6.3	5.5	6.6	7.0	7.0	7.4	5.9	5.5	4.7	5.1	4.6
2008	4.4	5.0	4.1	4.3	5.4	7.4	4.6	5.5	4.3	4.4	4.3	3.5	4.4	4.8	4.7	5.0	3.5	2.9	2.0	2.3	1.7
2009	5.3	5.8	4.9	5.2	6.3	8.3	5.6	6.5	5.4	5.5	5.4	4.7	5.6	6.0	5.9	6.3	4.9	4.4	3.6	4.0	3.5
2010	5.3	5.8	4.9	5.2	6.3	8.2	5.5	6.4	5.4	5.5	5.4	4.7	5.6	5.9	5.9	6.2	4.9	4.4	3.7	4.0	3.6

U.K. Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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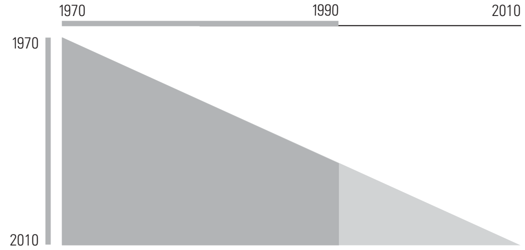
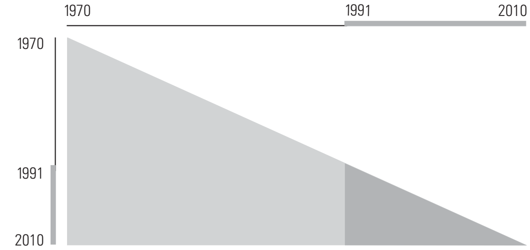
1989																				
1990																				
1991	5.7																			
1992	-2.9	-11.6																		
1993	3.5	2.5	16.5																	
1994	0.5	-1.3	3.9	-8.7																
1995	2.9	2.2	6.8	2.0	12.7															
1996	5.6	5.6	9.9	7.7	15.9	19.0														
1997	7.0	7.3	11.0	9.7	15.8	17.3	15.6													
1998	7.5	7.8	11.0	9.9	14.6	15.2	13.3	10.9												
1999	7.6	7.9	10.6	9.7	13.3	13.5	11.7	9.7	8.4											
2000	5.2	5.1	7.2	5.9	8.3	7.5	4.6	0.9	-4.1	-16.7										
2001	3.0	2.7	4.3	2.8	4.5	3.1	-0.1	-4.1	-9.0	-17.8	-18.8									
2002	1.0	0.6	1.8	0.2	1.3	-0.3	-3.6	-7.4	-12.0	-18.8	-19.8	-20.7								
2003	3.0	2.8	4.1	2.9	4.1	3.1	0.8	-1.7	-4.2	-7.4	-4.3	3.0	26.8							
2004	3.8	3.7	5.0	3.9	5.2	4.3	2.5	0.6	-1.1	-3.0	0.4	6.8	20.6	14.5						
2005	3.8	3.7	4.9	3.9	5.0	4.3	2.6	1.0	-0.4	-1.9	1.1	6.0	14.9	9.0	3.6					
2006	5.2	5.1	6.3	5.5	6.7	6.2	4.9	3.7	2.8	2.0	5.1	9.9	17.6	14.5	14.6	25.5				
2007	5.1	5.0	6.1	5.4	6.5	6.0	4.8	3.7	2.9	2.2	4.9	8.8	14.7	11.7	10.8	14.4	3.3			
2008	2.0	1.7	2.6	1.6	2.4	1.6	0.1	-1.3	-2.5	-3.7	-2.1	0.3	3.8	-0.8	-4.6	-7.3	-23.8	-50.9		
2009	3.8	3.7	4.6	3.9	4.7	4.2	3.0	2.0	1.1	0.4	2.3	5.0	8.6	5.6	3.8	3.9	-3.3	-6.7	37.5	
2010	3.9	3.8	4.6	3.9	4.7	4.2	3.1	2.2	1.4	0.8	2.6	4.9	8.1	5.5	4.0	4.0	-1.3	-2.9	21.1	4.7

U.K. Short-Horizon Equity Risk Premia (in Local Currency)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-13.1																				
1971	10.1	33.4																			
1972	9.3	20.5	7.7																		
1973	-1.7	2.1	-13.5	-34.6																	
1974	-14.0	-14.2	-30.1	-49.0	-63.4																
1975	11.6	16.6	12.4	14.0	38.3	140.0															
1976	8.9	12.6	8.4	8.6	23.0	66.2	-7.6														
1977	11.9	15.5	12.5	13.4	25.5	55.1	12.6	32.9													
1978	10.4	13.4	10.5	11.0	20.1	41.0	8.0	15.9	-1.1												
1979	9.2	11.7	9.0	9.2	16.4	32.4	5.5	9.9	-1.6	-2.0											
1980	9.7	12.0	9.7	9.9	16.3	29.5	7.5	11.2	4.0	6.6	15.2										
1981	8.8	10.8	8.6	8.7	14.1	25.1	6.0	8.7	2.7	4.0	6.9	-1.3									
1982	9.4	11.3	9.3	9.4	14.3	24.0	7.5	10.0	5.4	7.0	10.0	7.4	16.1								
1983	10.2	12.0	10.2	10.4	14.9	23.6	9.1	11.5	7.9	9.7	12.6	11.8	18.3	20.5							
1984	11.0	12.7	11.1	11.4	15.6	23.5	10.5	12.8	9.9	11.8	14.5	14.4	19.6	21.3	22.1						
1985	11.0	12.6	11.1	11.4	15.2	22.3	10.6	12.6	10.0	11.6	13.9	13.7	17.4	17.8	16.5	10.8					
1986	11.1	12.6	11.2	11.5	15.0	21.6	10.8	12.7	10.4	11.9	13.8	13.6	16.6	16.7	15.4	12.1	13.3				
1987	10.3	11.7	10.3	10.5	13.7	19.6	9.6	11.2	9.0	10.1	11.7	11.2	13.2	12.7	10.7	6.9	4.9	-3.5			
1988	9.7	11.0	9.7	9.8	12.8	18.2	8.9	10.2	8.2	9.1	10.3	9.7	11.3	10.5	8.5	5.1	3.2	-1.9	-0.3		
1989	10.4	11.6	10.4	10.6	13.4	18.5	9.8	11.2	9.4	10.3	11.6	11.1	12.7	12.2	10.8	8.6	8.0	6.2	11.1	22.5	
1990	8.8	9.9	8.6	8.7	11.2	15.9	7.6	8.7	6.9	7.5	8.4	7.7	8.7	7.8	6.0	3.3	1.8	-1.1	-0.3	-0.3	-23.1
1991	8.7	9.8	8.6	8.7	11.1	15.4	7.7	8.7	7.0	7.6	8.4	7.8	8.7	7.8	6.2	4.0	2.8	0.7	1.8	2.5	-7.5
1992	8.8	9.8	8.6	8.7	11.0	15.1	7.7	8.7	7.1	7.7	8.4	7.9	8.7	7.9	6.5	4.6	3.7	2.1	3.2	4.1	-2.0
1993	9.3	10.3	9.2	9.3	11.5	15.4	8.5	9.5	8.0	8.6	9.4	8.9	9.8	9.2	8.1	6.5	6.0	4.9	6.4	7.7	4.0
1994	8.4	9.3	8.3	8.3	10.4	14.1	7.4	8.3	6.8	7.3	7.9	7.4	8.1	7.4	6.2	4.7	4.0	2.8	3.7	4.4	0.7
1995	8.7	9.6	8.6	8.7	10.6	14.1	7.9	8.7	7.3	7.8	8.4	8.0	8.6	8.1	7.0	5.7	5.1	4.2	5.2	6.0	3.2
1996	8.8	9.6	8.7	8.7	10.6	13.9	7.9	8.7	7.4	7.9	8.5	8.1	8.7	8.2	7.2	6.0	5.6	4.8	5.7	6.4	4.1
1997	9.2	10.0	9.1	9.2	11.0	14.2	8.5	9.3	8.1	8.6	9.2	8.8	9.5	9.0	8.2	7.1	6.8	6.2	7.2	8.0	6.2
1998	9.2	10.0	9.1	9.2	10.9	14.0	8.6	9.3	8.2	8.6	9.2	8.9	9.5	9.0	8.3	7.3	7.0	6.5	7.4	8.2	6.6
1999	9.3	10.0	9.2	9.2	10.9	13.9	8.7	9.4	8.3	8.7	9.3	9.0	9.5	9.2	8.4	7.5	7.3	6.8	7.7	8.4	7.0
2000	8.6	9.3	8.5	8.5	10.1	13.0	7.9	8.5	7.5	7.9	8.3	8.0	8.5	8.1	7.3	6.4	6.1	5.6	6.3	6.8	5.4
2001	7.8	8.5	7.7	7.7	9.2	11.9	6.9	7.5	6.5	6.8	7.2	6.8	7.2	6.7	6.0	5.0	4.7	4.1	4.6	5.0	3.6
2002	6.8	7.4	6.5	6.5	7.9	10.5	5.7	6.2	5.1	5.4	5.7	5.3	5.6	5.0	4.2	3.2	2.8	2.1	2.5	2.7	1.2
2003	7.0	7.6	6.8	6.8	8.2	10.6	6.0	6.5	5.5	5.8	6.1	5.7	6.0	5.5	4.8	3.9	3.5	2.9	3.3	3.5	2.2
2004	7.0	7.6	6.8	6.8	8.1	10.5	6.0	6.5	5.6	5.8	6.1	5.7	6.1	5.6	4.9	4.0	3.7	3.1	3.5	3.8	2.5
2005	7.2	7.8	7.1	7.0	8.4	10.7	6.4	6.8	5.9	6.2	6.5	6.1	6.4	6.0	5.4	4.6	4.3	3.8	4.2	4.4	3.3
2006	7.3	7.9	7.1	7.1	8.4	10.6	6.5	6.9	6.0	6.3	6.6	6.3	6.6	6.2	5.6	4.8	4.5	4.1	4.5	4.7	3.7
2007	7.1	7.7	7.0	7.0	8.2	10.3	6.3	6.7	5.9	6.1	6.4	6.1	6.4	6.0	5.4	4.6	4.4	3.9	4.3	4.5	3.5
2008	6.1	6.6	5.9	5.8	7.0	9.1	5.1	5.5	4.6	4.8	5.0	4.7	4.9	4.5	3.8	3.1	2.7	2.2	2.5	2.7	1.6
2009	6.6	7.1	6.4	6.4	7.6	9.6	5.7	6.1	5.3	5.5	5.8	5.4	5.7	5.3	4.7	4.0	3.7	3.3	3.6	3.8	2.9
2010	6.8	7.2	6.6	6.6	7.7	9.6	5.9	6.3	5.5	5.7	6.0	5.7	5.9	5.5	5.0	4.3	4.1	3.7	4.0	4.2	3.3

U.K. Short-Horizon Equity Risk Premia (in Local Currency)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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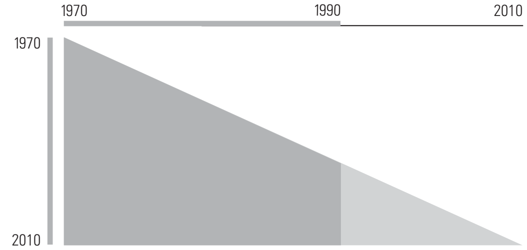
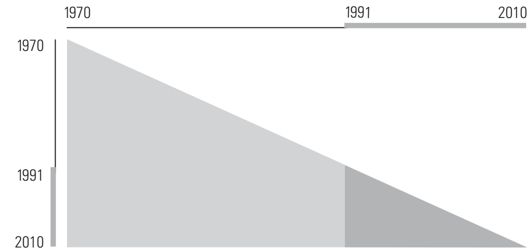
1991	8.1																			
1992	8.5	9.0																		
1993	13.0	15.5	21.9																	
1994	6.7	6.2	4.9	-12.2																
1995	8.5	8.6	8.5	1.7	15.7															
1996	8.7	8.8	8.8	4.4	12.7	9.6														
1997	10.4	10.8	11.2	8.5	15.4	15.3	20.9													
1998	10.3	10.6	10.9	8.7	13.9	13.3	15.1	9.3												
1999	10.4	10.6	10.9	9.0	13.3	12.7	13.7	10.1	10.9											
2000	8.3	8.3	8.2	6.2	9.3	8.0	7.6	3.2	0.2	-10.5										
2001	6.0	5.8	5.4	3.4	5.6	3.9	2.7	-1.8	-5.5	-13.7	-16.8									
2002	3.2	2.8	2.1	-0.1	1.5	-0.6	-2.3	-6.9	-10.9	-18.2	-22.1	-27.3								
2003	4.1	3.8	3.3	1.5	3.0	1.4	0.2	-3.2	-5.7	-9.9	-9.7	-6.1	15.1							
2004	4.3	4.0	3.6	2.0	3.4	2.0	1.1	-1.8	-3.6	-6.5	-5.5	-1.7	11.1	7.0						
2005	5.1	4.9	4.5	3.1	4.5	3.4	2.7	0.4	-0.9	-2.9	-1.3	2.6	12.5	11.2	15.4					
2006	5.4	5.2	4.9	3.6	4.9	4.0	3.4	1.4	0.5	-1.0	0.6	4.0	11.9	10.8	12.7	9.9				
2007	5.1	4.9	4.7	3.4	4.6	3.7	3.2	1.4	0.5	-0.8	0.6	3.5	9.7	8.3	8.7	5.4	0.9			
2008	3.0	2.7	2.3	1.0	1.9	0.9	0.1	-1.8	-2.9	-4.4	-3.6	-1.7	2.5	0.0	-1.8	-7.5	-16.2	-33.2		
2009	4.2	4.0	3.7	2.6	3.6	2.7	2.2	0.6	-0.1	-1.2	-0.2	1.9	6.0	4.5	4.0	1.2	-1.8	-3.1	27.0	
2010	4.6	4.4	4.2	3.1	4.1	3.3	2.9	1.5	0.8	-0.1	1.0	3.0	6.7	5.5	5.3	3.3	1.6	1.9	19.4	11.7

U.K. Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-13.1																				
1971	11.2	35.6																			
1972	9.8	21.3	7.1																		
1973	-1.2	2.8	-13.6	-34.2																	
1974	-13.8	-13.9	-30.4	-49.2	-64.1																
1975	8.6	13.0	7.3	7.4	28.2	120.6															
1976	6.5	9.7	4.6	4.0	16.7	57.1	-6.4														
1977	10.3	13.6	10.0	10.5	21.7	50.3	15.2	36.8													
1978	9.0	11.8	8.4	8.6	17.1	37.5	9.7	17.8	-1.2												
1979	7.9	10.2	7.0	7.0	13.9	29.5	6.8	11.1	-1.7	-2.2											
1980	8.6	10.8	8.1	8.2	14.3	27.3	8.7	12.4	4.3	7.0	16.3										
1981	7.8	9.7	7.2	7.2	12.3	23.3	7.0	9.7	3.0	4.3	7.6	-1.0									
1982	8.3	10.1	7.7	7.8	12.5	22.1	8.0	10.4	5.1	6.7	9.6	6.3	13.7								
1983	9.0	10.7	8.6	8.8	13.1	21.7	9.3	11.5	7.3	9.0	11.8	10.4	16.1	18.4							
1984	9.6	11.2	9.3	9.5	13.5	21.3	10.2	12.3	8.8	10.5	13.0	12.2	16.6	18.0	17.6						
1985	9.8	11.4	9.6	9.8	13.5	20.6	10.6	12.4	9.4	10.9	13.1	12.4	15.8	16.5	15.6	13.5					
1986	10.1	11.5	9.9	10.1	13.5	20.0	10.8	12.6	9.9	11.2	13.2	12.6	15.4	15.8	14.9	13.6	13.6				
1987	9.2	10.6	9.0	9.1	12.2	18.1	9.6	11.0	8.4	9.5	11.0	10.2	12.1	11.8	10.1	7.6	4.6	-4.5			
1988	8.7	10.0	8.5	8.5	11.4	16.8	8.8	10.1	7.6	8.5	9.7	8.9	10.3	9.7	8.0	5.6	3.0	-2.4	-0.3		
1989	9.3	10.5	9.1	9.2	11.9	17.0	9.6	10.8	8.7	9.6	10.7	10.1	11.5	11.2	10.0	8.5	7.2	5.1	9.9	20.1	
1990	7.6	8.6	7.2	7.2	9.6	14.2	7.1	8.1	5.9	6.5	7.3	6.4	7.2	6.4	4.6	2.5	0.3	-3.1	-2.6	-3.8	-27.7
1991	7.6	8.5	7.2	7.2	9.5	13.8	7.2	8.1	6.0	6.6	7.3	6.5	7.2	6.5	5.0	3.2	1.5	-0.9	0.0	0.1	-9.9
1992	7.6	8.5	7.2	7.2	9.4	13.5	7.2	8.0	6.1	6.6	7.3	6.6	7.2	6.6	5.3	3.7	2.3	0.5	1.5	1.9	-4.2
1993	8.1	9.1	7.8	7.9	10.0	13.9	8.0	8.8	7.1	7.6	8.3	7.7	8.4	8.0	6.9	5.7	4.7	3.5	4.8	5.8	2.2
1994	7.3	8.1	6.9	6.9	8.9	12.6	6.9	7.6	5.9	6.3	6.9	6.2	6.8	6.2	5.1	3.9	2.8	1.4	2.3	2.7	-0.8
1995	7.6	8.4	7.3	7.3	9.2	12.7	7.3	8.0	6.4	6.9	7.4	6.8	7.4	6.9	6.0	4.9	4.1	3.0	3.9	4.5	1.9
1996	7.7	8.5	7.4	7.5	9.3	12.6	7.5	8.2	6.6	7.1	7.6	7.1	7.6	7.2	6.3	5.4	4.6	3.8	4.7	5.3	3.2
1997	8.2	9.0	7.9	8.0	9.7	12.9	8.0	8.7	7.3	7.8	8.3	7.9	8.4	8.1	7.3	6.5	5.9	5.2	6.2	6.9	5.3
1998	8.2	9.0	8.0	8.0	9.7	12.8	8.1	8.8	7.4	7.8	8.4	7.9	8.5	8.1	7.5	6.7	6.2	5.6	6.5	7.2	5.7
1999	8.3	9.0	8.1	8.1	9.7	12.7	8.2	8.8	7.6	8.0	8.5	8.1	8.6	8.3	7.6	7.0	6.5	6.0	6.8	7.5	6.2
2000	7.7	8.4	7.5	7.5	9.0	11.8	7.5	8.1	6.8	7.2	7.6	7.2	7.6	7.3	6.6	5.9	5.4	4.8	5.6	6.1	4.8
2001	6.9	7.6	6.7	6.7	8.1	10.8	6.6	7.1	5.8	6.1	6.5	6.1	6.4	6.0	5.3	4.6	4.1	3.4	4.0	4.3	3.0
2002	5.8	6.4	5.5	5.4	6.8	9.3	5.2	5.6	4.4	4.6	4.9	4.4	4.7	4.2	3.5	2.7	2.1	1.3	1.7	1.9	0.5
2003	6.1	6.7	5.8	5.8	7.1	9.6	5.6	6.1	4.9	5.1	5.4	5.0	5.2	4.8	4.1	3.4	2.9	2.2	2.7	2.9	1.6
2004	6.2	6.8	5.9	5.8	7.1	9.5	5.7	6.1	5.0	5.2	5.5	5.1	5.3	4.9	4.3	3.6	3.1	2.5	2.9	3.1	2.0
2005	6.4	7.0	6.1	6.1	7.3	9.7	6.0	6.4	5.3	5.5	5.8	5.4	5.7	5.3	4.7	4.1	3.7	3.1	3.5	3.8	2.8
2006	6.5	7.1	6.3	6.2	7.5	9.7	6.1	6.5	5.5	5.7	6.0	5.6	5.9	5.6	5.0	4.4	4.0	3.5	4.0	4.2	3.3
2007	6.4	6.9	6.1	6.1	7.3	9.4	6.0	6.4	5.3	5.6	5.8	5.5	5.7	5.4	4.8	4.3	3.9	3.4	3.8	4.0	3.1
2008	5.6	6.1	5.3	5.2	6.4	8.4	5.0	5.4	4.4	4.6	4.8	4.4	4.6	4.2	3.7	3.1	2.6	2.1	2.5	2.6	1.7
2009	6.2	6.7	5.9	5.9	7.0	9.1	5.8	6.1	5.2	5.4	5.6	5.3	5.5	5.2	4.7	4.2	3.8	3.4	3.7	3.9	3.1
2010	6.3	6.8	6.1	6.0	7.1	9.1	5.9	6.3	5.4	5.6	5.8	5.5	5.7	5.4	4.9	4.4	4.1	3.7	4.0	4.2	3.5

U.K. Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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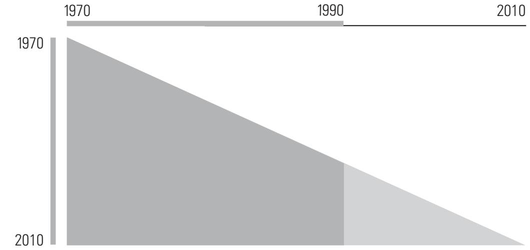
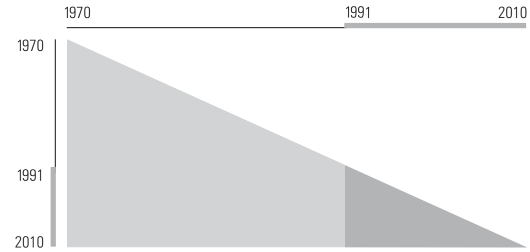
1991	7.8																			
1992	7.6	7.3																		
1993	12.2	14.4	21.4																	
1994	5.9	5.3	4.3	-12.9																
1995	7.8	7.8	8.0	1.3	15.6															
1996	8.3	8.4	8.7	4.4	13.1	10.6														
1997	10.0	10.4	11.0	8.4	15.4	15.4	20.2													
1998	9.9	10.2	10.7	8.6	13.9	13.4	14.7	9.3												
1999	10.0	10.3	10.7	8.9	13.3	12.7	13.4	10.0	10.6											
2000	8.0	8.0	8.1	6.2	9.4	8.2	7.6	3.4	0.4	-9.7										
2001	5.8	5.6	5.4	3.4	5.7	4.1	2.8	-1.6	-5.2	-13.1	-16.4									
2002	2.8	2.3	1.8	-0.3	1.2	-0.8	-2.7	-7.3	-11.4	-18.8	-23.3	-30.2								
2003	3.9	3.5	3.2	1.4	3.0	1.4	0.1	-3.3	-5.8	-9.9	-9.9	-6.7	16.8							
2004	4.1	3.9	3.6	1.9	3.4	2.1	1.0	-1.7	-3.6	-6.4	-5.6	-2.0	12.2	7.5						
2005	4.8	4.6	4.4	2.9	4.4	3.3	2.4	0.2	-1.1	-3.0	-1.7	2.0	12.7	10.7	13.8					
2006	5.2	5.0	4.8	3.6	4.9	4.0	3.3	1.4	0.5	-1.0	0.5	3.8	12.4	10.9	12.5	11.3				
2007	4.9	4.8	4.6	3.4	4.6	3.7	3.1	1.4	0.5	-0.8	0.5	3.4	10.1	8.4	8.7	6.1	0.9			
2008	3.3	3.0	2.8	1.5	2.6	1.6	0.8	-1.0	-2.0	-3.4	-2.6	-0.6	4.3	1.8	0.4	-4.1	-11.7	-24.4		
2009	4.7	4.5	4.4	3.3	4.4	3.6	3.0	1.6	0.9	0.0	1.0	3.2	8.0	6.5	6.3	4.4	2.2	2.8	30.0	
2010	5.0	4.9	4.8	3.8	4.8	4.1	3.6	2.4	1.8	1.0	2.1	4.1	8.4	7.2	7.1	5.8	4.4	5.6	20.6	11.3

U.S. Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-2.9																				
1971	2.5	8.0																			
1972	6.1	10.6	13.1																		
1973	-0.7	0.0	-4.0	-21.2																	
1974	-7.3	-8.5	-13.9	-27.5	-33.7																
1975	-1.2	-0.9	-3.1	-8.6	-2.2	29.2															
1976	1.2	1.9	0.7	-2.4	3.8	22.6	16.0														
1977	-0.7	-0.4	-1.8	-4.8	-0.7	10.3	0.9	-14.3													
1978	-0.8	-0.5	-1.7	-4.2	-0.8	7.4	0.1	-7.8	-1.3												
1979	0.3	0.6	-0.3	-2.2	0.9	7.9	2.5	-2.0	4.2	9.8											
1980	2.3	2.8	2.2	0.9	4.0	10.3	6.5	4.2	10.3	16.1	22.5										
1981	0.7	1.1	0.4	-1.1	1.5	6.5	2.7	0.0	3.6	5.3	3.0	-16.5									
1982	1.3	1.6	1.1	-0.1	2.2	6.7	3.5	1.4	4.5	6.0	4.7	-4.2	8.1								
1983	2.1	2.5	2.0	1.0	3.2	7.3	4.6	2.9	5.8	7.2	6.6	1.3	10.1	12.2							
1984	1.6	1.9	1.4	0.4	2.4	6.0	3.4	1.9	4.2	5.1	4.2	-0.4	4.9	3.4	-5.5						
1985	2.7	3.1	2.8	2.0	3.9	7.3	5.1	3.9	6.2	7.3	6.9	3.8	8.8	9.1	7.5	20.5					
1986	3.2	3.5	3.2	2.5	4.4	7.5	5.6	4.5	6.6	7.6	7.3	4.7	9.0	9.2	8.2	15.1	9.7				
1987	2.8	3.2	2.9	2.2	3.9	6.7	4.9	3.9	5.7	6.5	6.0	3.7	7.0	6.8	5.5	9.2	3.5	-2.7			
1988	3.1	3.4	3.1	2.5	4.1	6.8	5.1	4.2	5.9	6.6	6.2	4.2	7.1	7.0	5.9	8.8	4.9	2.5	7.6		
1989	4.1	4.4	4.2	3.7	5.3	7.9	6.4	5.6	7.3	8.1	7.9	6.3	9.1	9.2	8.8	11.6	9.4	9.3	15.3	22.9	
1990	3.3	3.7	3.4	2.9	4.3	6.7	5.2	4.4	5.8	6.4	6.1	4.5	6.8	6.7	5.9	7.8	5.2	4.1	6.4	5.8	-11.3
1991	4.2	4.5	4.4	3.9	5.3	7.6	6.2	5.6	7.0	7.7	7.5	6.1	8.4	8.4	7.9	9.9	8.1	7.8	10.4	11.3	5.5
1992	4.0	4.4	4.2	3.7	5.0	7.2	5.9	5.3	6.6	7.1	6.9	5.6	7.6	7.6	7.1	8.7	7.0	6.5	8.4	8.5	3.8
1993	4.0	4.3	4.1	3.7	4.9	7.0	5.7	5.1	6.3	6.9	6.6	5.4	7.2	7.2	6.7	8.0	6.5	6.0	7.5	7.4	3.6
1994	3.6	3.9	3.7	3.3	4.4	6.4	5.2	4.6	5.7	6.1	5.9	4.7	6.3	6.1	5.6	6.7	5.2	4.6	5.6	5.3	1.8
1995	4.6	4.9	4.8	4.4	5.6	7.5	6.4	5.9	7.0	7.5	7.4	6.3	8.0	8.0	7.6	8.8	7.6	7.4	8.7	8.8	6.5
1996	5.1	5.4	5.3	5.0	6.1	7.9	6.9	6.4	7.5	8.0	7.9	7.0	8.6	8.6	8.3	9.5	8.5	8.4	9.6	9.8	8.0
1997	5.9	6.2	6.1	5.8	7.0	8.7	7.8	7.4	8.5	9.0	9.0	8.2	9.7	9.8	9.6	10.8	10.0	10.0	11.3	11.7	10.3
1998	6.4	6.8	6.7	6.5	7.6	9.3	8.4	8.1	9.2	9.7	9.7	9.0	10.5	10.6	10.5	11.7	11.0	11.1	12.3	12.8	11.7
1999	6.7	7.1	7.0	6.8	7.9	9.6	8.7	8.4	9.5	10.0	10.0	9.3	10.7	10.9	10.8	11.9	11.3	11.4	12.6	13.0	12.1
2000	6.0	6.3	6.3	6.0	7.0	8.6	7.8	7.4	8.4	8.8	8.8	8.1	9.4	9.4	9.3	10.2	9.5	9.5	10.4	10.7	9.5
2001	5.3	5.5	5.5	5.2	6.1	7.6	6.8	6.4	7.3	7.7	7.6	6.9	8.0	8.0	7.8	8.6	7.8	7.7	8.4	8.5	7.3
2002	4.3	4.5	4.4	4.1	5.0	6.4	5.5	5.1	5.9	6.2	6.0	5.3	6.3	6.2	5.9	6.6	5.7	5.5	6.0	5.9	4.6
2003	4.9	5.1	5.0	4.7	5.6	7.0	6.2	5.8	6.6	6.9	6.8	6.1	7.1	7.1	6.8	7.5	6.7	6.6	7.1	7.1	6.0
2004	4.9	5.1	5.0	4.8	5.6	6.9	6.2	5.8	6.6	6.9	6.7	6.1	7.1	7.0	6.8	7.4	6.7	6.5	7.1	7.0	6.0
2005	4.8	5.0	4.9	4.6	5.4	6.7	6.0	5.6	6.3	6.6	6.5	5.8	6.8	6.7	6.5	7.0	6.4	6.2	6.7	6.6	5.6
2006	4.9	5.2	5.1	4.8	5.6	6.9	6.1	5.8	6.5	6.8	6.7	6.1	7.0	6.9	6.7	7.2	6.6	6.4	6.9	6.9	5.9
2007	4.8	5.0	4.9	4.7	5.5	6.7	6.0	5.6	6.3	6.6	6.4	5.9	6.7	6.7	6.4	6.9	6.3	6.2	6.6	6.6	5.6
2008	3.6	3.8	3.7	3.4	4.1	5.2	4.5	4.2	4.8	5.0	4.8	4.2	4.9	4.8	4.5	4.9	4.2	4.0	4.3	4.2	3.2
2009	4.1	4.3	4.2	4.0	4.7	5.8	5.1	4.7	5.3	5.5	5.4	4.8	5.6	5.5	5.2	5.6	5.0	4.8	5.2	5.1	4.2
2010	4.3	4.5	4.4	4.1	4.8	5.9	5.2	4.9	5.5	5.7	5.6	5.0	5.8	5.7	5.4	5.8	5.3	5.1	5.4	5.3	4.5

U.S. Long-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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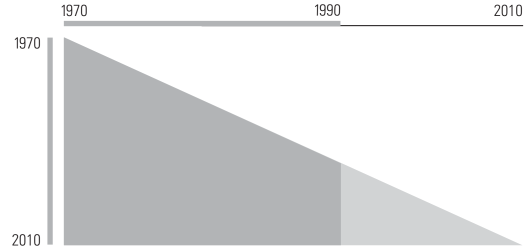
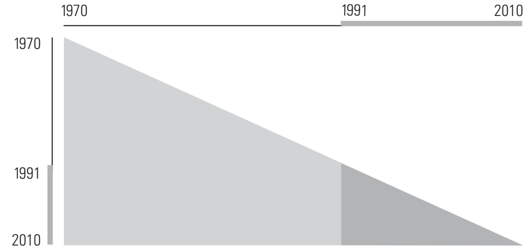
1991	22.2																			
1992	11.3	0.4																		
1993	8.5	1.6	2.9																	
1994	5.1	-0.7	-1.2	-5.3																
1995	10.0	7.0	9.2	12.4	30.0															
1996	11.2	9.0	11.1	13.8	23.4	16.8														
1997	13.4	11.9	14.2	17.1	24.5	21.8	26.7													
1998	14.6	13.5	15.6	18.2	24.1	22.1	24.7	22.7												
1999	14.7	13.7	15.6	17.7	22.3	20.4	21.6	19.1	15.5											
2000	11.6	10.5	11.7	13.0	16.0	13.2	12.3	7.5	-0.1	-15.6										
2001	9.0	7.7	8.5	9.2	11.2	8.1	6.4	1.3	-5.8	-16.5	-17.4									
2002	5.9	4.5	4.9	5.1	6.4	3.0	0.7	-4.5	-11.3	-20.2	-22.6	-27.7								
2003	7.3	6.1	6.6	7.0	8.3	5.6	4.0	0.2	-4.3	-9.2	-7.1	-1.9	23.9							
2004	7.2	6.1	6.5	6.9	8.1	5.6	4.2	1.0	-2.6	-6.2	-3.8	0.7	14.9	5.9						
2005	6.7	5.6	6.0	6.3	7.4	5.1	3.8	0.9	-2.2	-5.1	-3.0	0.6	10.0	3.0	0.2					
2006	7.0	6.0	6.4	6.7	7.7	5.6	4.5	2.1	-0.5	-2.8	-0.7	2.7	10.3	5.7	5.7	11.1				
2007	6.6	5.7	6.0	6.2	7.1	5.2	4.2	1.9	-0.4	-2.4	-0.5	2.3	8.3	4.5	4.0	5.9	0.6			
2008	4.0	2.9	3.1	3.1	3.7	1.6	0.4	-2.0	-4.5	-6.7	-5.6	-3.9	0.0	-4.7	-7.4	-9.9	-20.4	-41.4		
2009	5.0	4.0	4.2	4.3	5.0	3.2	2.1	0.1	-2.0	-3.7	-2.4	-0.6	3.3	-0.1	-1.3	-1.7	-5.9	-9.2	23.0	
2010	5.3	4.4	4.6	4.7	5.3	3.7	2.7	0.9	-0.9	-2.4	-1.1	0.7	4.3	1.5	0.7	0.8	-1.8	-2.5	16.9	10.8

U.S. Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	-2.7																				
1971	3.6	9.9																			
1972	7.5	12.5	15.2																		
1973	0.2	1.2	-3.2	-21.6																	
1974	-6.7	-7.8	-13.6	-28.0	-34.5																
1975	-0.4	0.1	-2.4	-8.2	-1.5	31.4															
1976	2.4	3.2	1.9	-1.5	5.3	25.1	18.8														
1977	0.5	1.0	-0.5	-3.6	0.9	12.7	3.3	-12.3													
1978	0.4	0.8	-0.5	-3.1	0.6	9.3	2.0	-6.4	-0.6												
1979	1.2	1.6	0.6	-1.5	1.9	9.1	3.5	-1.6	3.8	8.2											
1980	3.0	3.6	2.9	1.3	4.6	11.1	7.1	4.2	9.6	14.8	21.3										
1981	1.1	1.5	0.6	-1.0	1.6	6.8	2.6	-0.6	2.3	3.3	0.8	-19.6									
1982	1.9	2.3	1.6	0.2	2.6	7.3	3.8	1.3	4.1	5.2	4.2	-4.3	11.0								
1983	2.7	3.2	2.6	1.4	3.8	8.0	5.1	3.1	5.7	6.9	6.6	1.7	12.4	13.8							
1984	2.3	2.7	2.1	1.0	3.1	6.8	4.1	2.3	4.3	5.2	4.6	0.4	7.1	5.1	-3.6						
1985	3.7	4.1	3.7	2.8	4.8	8.4	6.1	4.7	6.8	7.9	7.8	5.1	11.3	11.4	10.2	24.0					
1986	4.2	4.6	4.3	3.5	5.4	8.7	6.7	5.5	7.4	8.4	8.5	6.3	11.5	11.7	11.0	18.3	12.5				
1987	3.9	4.3	4.0	3.2	5.0	8.1	6.1	5.0	6.7	7.5	7.4	5.4	9.6	9.3	8.2	12.1	6.1	-0.2			
1988	4.3	4.7	4.4	3.7	5.4	8.2	6.4	5.4	7.0	7.8	7.7	6.0	9.7	9.5	8.6	11.6	7.5	5.0	10.3		
1989	5.2	5.6	5.4	4.8	6.5	9.2	7.6	6.8	8.4	9.2	9.3	7.9	11.4	11.4	11.0	14.0	11.5	11.1	16.8	23.3	
1990	4.5	4.8	4.6	4.0	5.5	8.0	6.4	5.5	6.9	7.5	7.4	6.1	8.9	8.6	7.9	9.8	7.0	5.6	7.6	6.2	-10.9
1991	5.4	5.8	5.6	5.1	6.5	9.0	7.6	6.8	8.2	8.8	8.9	7.8	10.5	10.4	10.0	12.0	10.0	9.5	11.9	12.4	7.0
1992	5.3	5.7	5.5	5.0	6.4	8.7	7.3	6.6	7.9	8.5	8.5	7.5	9.9	9.8	9.4	11.0	9.1	8.6	10.3	10.3	6.0
1993	5.4	5.8	5.6	5.1	6.5	8.6	7.3	6.7	7.8	8.4	8.4	7.4	9.7	9.6	9.2	10.6	8.9	8.4	9.8	9.7	6.3
1994	5.1	5.4	5.2	4.8	6.0	8.0	6.8	6.1	7.2	7.7	7.7	6.7	8.7	8.6	8.1	9.3	7.6	7.0	8.0	7.7	4.5
1995	6.1	6.5	6.3	6.0	7.2	9.2	8.1	7.5	8.6	9.2	9.2	8.4	10.4	10.4	10.1	11.3	10.1	9.8	11.0	11.1	9.1
1996	6.6	6.9	6.8	6.4	7.7	9.6	8.5	8.0	9.1	9.6	9.7	9.0	10.9	10.9	10.7	11.9	10.8	10.6	11.8	12.0	10.3
1997	7.3	7.7	7.6	7.3	8.5	10.4	9.4	9.0	10.0	10.6	10.7	10.1	12.0	12.0	11.9	13.1	12.2	12.2	13.4	13.8	12.6
1998	7.9	8.3	8.2	7.9	9.1	10.9	10.0	9.6	10.7	11.3	11.4	10.9	12.7	12.8	12.7	13.9	13.1	13.1	14.3	14.8	13.8
1999	8.2	8.5	8.5	8.3	9.4	11.2	10.3	9.9	11.0	11.5	11.7	11.2	12.9	13.0	12.9	14.0	13.3	13.4	14.5	14.9	14.1
2000	7.4	7.8	7.7	7.4	8.5	10.1	9.3	8.9	9.8	10.3	10.4	9.9	11.4	11.4	11.3	12.2	11.4	11.4	12.2	12.4	11.4
2001	6.7	7.0	6.9	6.6	7.6	9.2	8.3	7.9	8.8	9.2	9.2	8.6	10.0	10.0	9.8	10.6	9.7	9.5	10.2	10.2	9.2
2002	5.8	6.0	5.9	5.6	6.6	8.0	7.1	6.7	7.5	7.8	7.8	7.2	8.4	8.3	8.0	8.7	7.8	7.5	8.0	7.8	6.6
2003	6.4	6.7	6.6	6.3	7.3	8.7	7.9	7.5	8.2	8.6	8.6	8.1	9.3	9.2	9.0	9.7	8.9	8.7	9.2	9.1	8.1
2004	6.5	6.8	6.7	6.4	7.3	8.7	7.9	7.6	8.3	8.6	8.6	8.1	9.3	9.3	9.0	9.7	8.9	8.7	9.2	9.2	8.2
2005	6.4	6.6	6.6	6.3	7.2	8.5	7.7	7.4	8.1	8.4	8.4	7.9	9.0	8.9	8.7	9.3	8.6	8.4	8.8	8.7	7.8
2006	6.5	6.8	6.7	6.4	7.3	8.6	7.8	7.5	8.2	8.5	8.5	8.0	9.1	9.0	8.8	9.4	8.7	8.5	8.9	8.9	8.0
2007	6.4	6.6	6.5	6.3	7.1	8.3	7.6	7.3	7.9	8.2	8.2	7.7	8.8	8.7	8.5	9.0	8.3	8.1	8.5	8.4	7.6
2008	5.2	5.4	5.3	5.0	5.8	7.0	6.2	5.8	6.4	6.7	6.6	6.1	7.0	6.9	6.6	7.0	6.3	6.0	6.3	6.1	5.2
2009	5.7	6.0	5.9	5.6	6.4	7.5	6.8	6.5	7.0	7.3	7.3	6.8	7.7	7.6	7.4	7.8	7.1	6.9	7.2	7.1	6.3
2010	6.0	6.2	6.1	5.8	6.6	7.7	7.1	6.7	7.3	7.5	7.5	7.0	8.0	7.9	7.6	8.1	7.4	7.2	7.5	7.4	6.7

U.S. Short-Horizon Equity Risk Premia (in U.S. Dollars)



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1970																				
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1991	24.9																			
1992	14.5	4.1																		
1993	12.1	5.6	7.2																	
1994	8.4	2.9	2.3	-2.6																
1995	13.1	10.2	12.2	14.7	32.0															
1996	13.9	11.7	13.6	15.7	24.9	17.8														
1997	15.9	14.4	16.5	18.8	25.9	22.9	28.1													
1998	16.9	15.8	17.7	19.8	25.4	23.2	25.9	23.7												
1999	16.8	15.8	17.5	19.2	23.6	21.5	22.7	20.0	16.4											
2000	13.7	12.4	13.4	14.3	17.2	14.2	13.3	8.4	0.7	-15.0										
2001	11.0	9.6	10.2	10.6	12.5	9.2	7.5	2.3	-4.8	-15.4	-15.7									
2002	8.1	6.6	6.8	6.8	7.9	4.5	2.3	-2.9	-9.5	-18.2	-19.7	-23.7								
2003	9.6	8.3	8.7	8.9	10.1	7.4	5.9	2.2	-2.1	-6.7	-3.9	2.0	27.7							
2004	9.6	8.4	8.8	8.9	10.1	7.6	6.4	3.3	-0.1	-3.4	-0.5	4.5	18.7	9.7						
2005	9.1	8.0	8.3	8.3	9.3	7.1	5.9	3.1	0.2	-2.5	0.0	3.9	13.1	5.8	1.9					
2006	9.2	8.2	8.5	8.6	9.5	7.4	6.4	4.0	1.5	-0.6	1.8	5.3	12.6	7.5	6.5	11.0				
2007	8.7	7.7	7.9	8.0	8.8	6.9	5.9	3.7	1.4	-0.4	1.7	4.6	10.2	5.9	4.6	5.9	0.8			
2008	6.1	5.0	5.0	4.9	5.4	3.4	2.2	-0.2	-2.6	-4.7	-3.4	-1.6	2.1	-3.0	-6.2	-8.9	-18.9	-38.6		
2009	7.2	6.2	6.3	6.2	6.8	5.0	4.0	2.0	0.1	-1.6	-0.1	1.9	5.6	1.9	0.3	-0.1	-3.8	-6.1	26.4	
2010	7.5	6.6	6.8	6.7	7.3	5.7	4.8	3.0	1.3	-0.1	1.4	3.3	6.7	3.7	2.7	2.9	0.9	0.9	20.7	14.9

ibbotson

Canadian Risk Premia Over Time Report 2006

Canadian Risk Premia Over Time Report

(Introduction)

The "Canadian Risk Premia over Time Report" provides long-horizon equity risk premia for your choice of historical time periods from 1936-2005, which allows you to customize your analysis by choosing your own start and end date. Premia are presented in both Canadian dollars and U.S. dollars (U.S. dollar denominated data available from 1939-2005 given the availability of exchange rate data).

Methodology

The equity risk premium is calculated by subtracting the long-term arithmetic average of the yield on the riskless asset from the long-term arithmetic average stock market total return (measured over the same period as the riskless asset). Then the arithmetic mean (simple average) annual return for the two components is calculated. Once these averages are computed, the average for the riskless asset is subtracted from the average stock market return to form the estimate of the equity risk premium. For example, if Canada had an average stock market return of 12.50 percent and an average yield on its riskless asset was 8.00 percent, the equity risk premium would be 4.5 percent (12.50 – 8.00).

The equity risk premia presented in U.S. dollars have been converted at the prevailing exchange rate. These figures do not always correspond to the equity risk premium in Canadian dollar terms, since currency fluctuations effect the return on the riskless asset and the market in varying magnitudes. For example, suppose the Canadian dollar depreciates against the U.S. dollar by 2.0 percent in a given year. Using the same example as above, the return on the market in U.S. dollar terms would be 10.25 percent $[(1+0.125)\times(1-0.02)-1]$, and the return on the riskless asset would be 5.84 percent $[(1+0.08)\times(1-0.02)-1]$. The resulting equity risk premium would be 4.41 percent (10.25 – 5.84) compared to 4.50 percent in Canadian dollar terms.

Riskless Asset

From 1936-1957, the yield on the Canadian long-term government bond from the Canadian Institute of Actuaries was used to represent the riskless asset.*Generally, the income return is used to represent the riskless asset since it is the completely riskless portion of a bond's return (Treasury securities are subject to price risk). Unexpected changes in yields will cause capital losses or gains in the fixed-income securities. Historical income returns are unbiased estimators of the returns that investors expected. During the 1936-1957 period, all the necessary data was unavailable to calculate the income return. Therefore, the year-end yield was used to approximate the riskless return for the following year, as it was the unbiased estimate of expected return at that point in time.

From 1957 to present, the income return is calculated from yields provided by the International Monetary Fund International Financial Statistics. The Canadian Long-term Government bond income return is used. Long-term series refers to issues with original maturity of 10 years or more. Returns are calculated assuming a single bond is bought at par (i.e., the coupon equals the market yield) at the beginning of each period. The bond is "held" over the period and "sold" at the end of the period at the then-prevailing market yield. The end-of-period price is calculated as a function of the coupon, yield, and maturity remaining at period-end. The return in excess of yield (capital appreciation) is then derived as the change in price over the period, divided by the beginning-of-period price (i.e., divided by par). The yield is converted to an income return by lagging it (dividing it by 12) one period.

Market Returns

The Canadian market is represented by the S&P/TSX Composite Index. From 1957 to present, the Toronto Stock Exchange has provided market returns for the S&P/TSX Composite Index. Before 1957, the Canadian Institute of Actuaries provided market returns. The S&P/TSX Composite Index is a market-float-weighted index of the largest capitalized, Canadian incorporated securities traded on the Toronto Stock Exchange (1936-2005). The market value of the outstanding index of the shares is adjusted in order to subtract significant controlling blocks, resulting in the adjusted market float value. Since 1977, dividends have been reinvested at the index level on a daily basis.

Canadian Risk Premia Over Time Report
(Introduction)

The index will be reviewed quarterly and all stocks that do not meet the requirements of the S&P/TSX Composite Index maintenance policies will be removed. Stocks to be added will be selected using the criteria for inclusion.

Selection criteria for the annual constitution of the index:

1) Inclusion: All common shares and residual equity of a company may be included.
2) Excluded: As of February 18, 1997, Limited Partnerships, Royalty Trust, and REITs are not included. Preferred shares, exchangeable shares, mutual fund corporations, warrants and other financial instruments are also not included, though there can be exceptions.
3) Must be listed on the TSX for at least a year. S&P shall have the discretion to add IPO's at any time after its listing date, however, they will not be considered a part of the eligible pool.
4) Trading volume, value and transactions for the year before consideration of inclusion must have been at least 0.025% of the sum of all eligible companies trading volume, value and number of transactions, as determined by trading on the Toronto Stock Exchange. Standard & Poor's reserves the right to review and modify the threshold as market conditions dictate.

For a more detailed explanation on the S&P/TSX Composite Index, including recent changes to the index and construction methodology, please visit www.standardandpoors.com.

Exchange Rates

The Canadian exchange rate data comes from the three sources listed below:

1936 – 1959: Canadian Economic Statistics, 1924-1997 (Canadian Institute of Actuaries)*

1960 - 1987: OECD Main Economic Indicators Historical Statistics (Organization for Economic Cooperation & Development)

1988 - present: The Wall Street Journal

Raw data are expressed as a ratio of foreign currency to U.S. dollars. Ibbotson Associates calculates exchange returns as the monthly percentage change in exchange rates, representing the return to a foreign investor holding non-interest-bearing U.S. currency.

* This data is used with permission of the Canadian Institute of Actuaries from the "Report of Canadian Economic Statistics."

How to Use

The report is arranged with start dates across the columns and end dates down the rows. If, for example, you want to determine the equity risk premium for Canada in Canadian dollars using the historical window of 1950-1993, find the 1950 start-date column and the 1993 end-date row. The intersection provides a statistic of 5.2 percent.

The equity risk premium presented in this report may be used in conjunction with the capital asset pricing model (CAPM) or the build-up method of estimating the cost of capital.

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1936	1937	1938	1939	1940	1941	1942	1943	1944	1945	1946	1947	1948	1949
1936	22.4													
1937	1.8	-18.8												
1938	3.2	-6.4	6.0											
1939	1.7	-5.2	1.5	-2.9										
1940	-3.1	-9.5	-6.4	-12.6	-22.3									
1941	-2.8	-7.9	-5.1	-8.9	-11.8	-1.4								
1942	-0.9	-4.7	-1.9	-3.9	-4.3	4.8	10.9							
1943	1.3	-1.7	1.2	0.2	1.0	8.7	13.7	16.6						
1944	2.3	-0.2	2.5	1.9	2.9	9.2	12.7	13.5	10.5					
1945	5.4	3.5	6.3	6.4	7.9	13.9	17.8	20.0	21.8	33.1				
1946	4.5	2.7	5.1	5.0	6.1	10.9	13.3	13.9	13.0	14.3	-4.4			
1947	3.9	2.3	4.4	4.2	5.1	9.0	10.7	10.7	9.2	8.8	-3.3	-2.3		
1948	4.4	2.9	4.8	4.7	5.6	9.1	10.6	10.5	9.3	9.0	1.0	3.6	9.6	
1949	5.5	4.2	6.1	6.1	7.0	10.2	11.7	11.8	11.0	11.1	5.6	9.0	14.6	19.7
1950	8.1	7.1	9.1	9.4	10.5	13.8	15.5	16.0	15.9	16.9	13.6	18.1	24.9	32.6
1951	9.0	8.1	10.0	10.3	11.4	14.4	16.0	16.6	16.6	17.5	14.9	18.7	24.0	28.8
1952	8.2	7.3	9.1	9.3	10.2	12.9	14.2	14.6	14.3	14.8	12.2	15.0	18.5	20.7
1953	7.7	6.8	8.4	8.6	9.4	11.8	12.9	13.1	12.8	13.0	10.5	12.7	15.2	16.3
1954	9.1	8.4	10.0	10.3	11.1	13.5	14.7	15.0	14.8	15.3	13.3	15.5	18.0	19.5
1955	9.9	9.3	10.8	11.1	12.0	14.3	15.4	15.7	15.6	16.1	14.4	16.5	18.9	20.2
1956	9.9	9.3	10.8	11.0	11.9	14.0	15.0	15.3	15.2	15.6	14.0	15.9	17.9	18.9
1957	8.3	7.7	9.0	9.2	9.8	11.7	12.5	12.6	12.4	12.5	10.8	12.2	13.6	14.1
1958	9.2	8.6	9.9	10.1	10.7	12.6	13.4	13.6	13.4	13.6	12.1	13.4	14.9	15.4
1959	8.8	8.2	9.4	9.6	10.2	11.9	12.6	12.8	12.5	12.6	11.2	12.4	13.6	14.0
1960	8.3	7.7	8.8	9.0	9.5	11.1	11.8	11.8	11.6	11.6	10.2	11.3	12.3	12.5
1961	9.0	8.5	9.6	9.8	10.4	11.9	12.6	12.7	12.5	12.6	11.3	12.3	13.4	13.7
1962	8.2	7.7	8.8	8.9	9.4	10.8	11.4	11.4	11.2	11.2	9.9	10.8	11.7	11.8
1963	8.3	7.8	8.8	8.9	9.4	10.8	11.4	11.4	11.1	11.2	10.0	10.8	11.6	11.7
1964	8.7	8.2	9.3	9.4	9.9	11.2	11.8	11.8	11.6	11.6	10.5	11.3	12.1	12.3
1965	8.5	8.0	9.0	9.1	9.5	10.8	11.3	11.3	11.1	11.1	10.0	10.8	11.5	11.7
1966	7.8	7.3	8.2	8.3	8.7	9.9	10.4	10.4	10.1	10.1	9.0	9.6	10.3	10.3
1967	8.0	7.5	8.4	8.4	8.9	10.0	10.4	10.4	10.2	10.2	9.1	9.8	10.4	10.4
1968	8.2	7.8	8.6	8.7	9.1	10.2	10.6	10.6	10.4	10.4	9.4	10.0	10.6	10.7
1969	7.7	7.3	8.1	8.2	8.5	9.6	10.0	9.9	9.7	9.7	8.7	9.2	9.8	9.8
1970	7.2	6.7	7.5	7.5	7.9	8.9	9.2	9.2	8.9	8.8	7.9	8.4	8.8	8.8
1971	7.0	6.5	7.3	7.3	7.7	8.6	9.0	8.9	8.6	8.5	7.6	8.1	8.5	8.5
1972	7.4	6.9	7.7	7.7	8.0	9.0	9.3	9.3	9.0	9.0	8.1	8.6	9.0	9.0
1973	7.0	6.6	7.3	7.3	7.6	8.5	8.8	8.7	8.5	8.4	7.5	8.0	8.4	8.3
1974	5.9	5.5	6.1	6.1	6.4	7.3	7.5	7.4	7.1	7.0	6.1	6.5	6.8	6.7
1975	6.0	5.6	6.2	6.2	6.5	7.3	7.6	7.5	7.2	7.1	6.2	6.6	6.9	6.8
1976	5.9	5.5	6.1	6.1	6.4	7.2	7.4	7.3	7.0	6.9	6.1	6.4	6.7	6.6
1977	5.8	5.4	6.0	6.0	6.3	7.0	7.3	7.2	6.9	6.8	5.9	6.3	6.6	6.5
1978	6.2	5.8	6.4	6.4	6.6	7.4	7.6	7.5	7.3	7.2	6.4	6.7	7.0	6.9
1979	6.8	6.5	7.1	7.1	7.3	8.1	8.3	8.3	8.0	8.0	7.2	7.6	7.9	7.8
1980	7.1	6.7	7.3	7.4	7.6	8.4	8.6	8.5	8.3	8.3	7.6	7.9	8.2	8.2

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1936	1937	1938	1939	1940	1941	1942	1943	1944	1945	1946	1947	1948	1949
1981	6.4	6.1	6.6	6.6	6.9	7.6	7.8	7.7	7.5	7.4	6.7	7.0	7.3	7.2
1982	6.1	5.7	6.3	6.3	6.5	7.2	7.4	7.3	7.1	7.0	6.3	6.6	6.8	6.7
1983	6.4	6.1	6.7	6.7	6.9	7.6	7.8	7.7	7.5	7.4	6.7	7.0	7.3	7.2
1984	6.0	5.7	6.2	6.2	6.4	7.1	7.3	7.2	6.9	6.8	6.2	6.5	6.7	6.6
1985	6.2	5.8	6.4	6.4	6.6	7.2	7.4	7.3	7.1	7.0	6.4	6.6	6.9	6.8
1986	6.0	5.7	6.2	6.2	6.4	7.0	7.2	7.1	6.9	6.8	6.2	6.5	6.7	6.6
1987	5.8	5.5	6.0	6.0	6.2	6.8	7.0	6.9	6.7	6.6	6.0	6.2	6.4	6.3
1988	5.8	5.4	5.9	5.9	6.1	6.7	6.8	6.8	6.5	6.5	5.8	6.1	6.3	6.2
1989	5.9	5.5	6.0	6.0	6.2	6.8	6.9	6.9	6.6	6.6	6.0	6.2	6.4	6.3
1990	5.3	5.0	5.4	5.4	5.6	6.1	6.3	6.2	6.0	5.9	5.3	5.5	5.7	5.6
1991	5.2	4.9	5.4	5.3	5.5	6.1	6.2	6.1	5.9	5.8	5.2	5.4	5.6	5.5
1992	5.0	4.6	5.1	5.1	5.2	5.7	5.9	5.8	5.6	5.5	4.9	5.1	5.2	5.1
1993	5.3	5.0	5.4	5.4	5.6	6.1	6.2	6.1	5.9	5.8	5.3	5.5	5.6	5.6
1994	5.1	4.8	5.2	5.2	5.3	5.8	6.0	5.9	5.7	5.6	5.0	5.2	5.4	5.3
1995	5.1	4.8	5.2	5.2	5.3	5.8	6.0	5.9	5.7	5.6	5.0	5.2	5.4	5.3
1996	5.3	5.1	5.5	5.4	5.6	6.1	6.2	6.1	5.9	5.9	5.3	5.5	5.7	5.6
1997	5.4	5.1	5.5	5.5	5.6	6.1	6.3	6.2	6.0	5.9	5.4	5.6	5.7	5.7
1998	5.2	4.9	5.3	5.3	5.4	5.9	6.0	5.9	5.8	5.7	5.1	5.3	5.5	5.4
1999	5.5	5.2	5.6	5.6	5.8	6.3	6.4	6.3	6.1	6.0	5.5	5.7	5.9	5.8
2000	5.5	5.2	5.6	5.6	5.7	6.2	6.3	6.2	6.0	6.0	5.5	5.6	5.8	5.7
2001	5.1	4.8	5.2	5.2	5.3	5.8	5.9	5.8	5.6	5.5	5.0	5.2	5.3	5.3
2002	4.7	4.5	4.8	4.8	4.9	5.4	5.5	5.4	5.2	5.1	4.6	4.8	4.9	4.8
2003	5.0	4.7	5.1	5.1	5.2	5.6	5.7	5.7	5.5	5.4	4.9	5.1	5.2	5.1
2004	5.1	4.8	5.2	5.1	5.3	5.7	5.8	5.7	5.5	5.5	5.0	5.2	5.3	5.2
2005	5.3	5.0	5.4	5.4	5.5	5.9	6.0	5.9	5.8	5.7	5.2	5.4	5.5	5.5

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
1936														
1937														
1938														
1939														
1940														
1941														
1942														
1943														
1944														
1945														
1946														
1947														
1948														
1949														
1950	45.6													
1951	33.4	21.2												
1952	21.0	8.8	-3.7											
1953	15.4	5.4	-2.5	-1.4										
1954	19.4	12.9	10.1	17.0	35.3									
1955	20.3	15.2	13.7	19.5	30.0	24.6								
1956	18.8	14.4	13.0	17.2	23.3	17.3	10.1							
1957	13.4	8.8	6.7	8.8	11.3	3.3	-7.3	-24.7						
1958	14.9	11.1	9.7	11.9	14.5	9.3	4.2	1.3	27.3					
1959	13.4	9.8	8.4	10.1	12.1	7.4	3.1	0.8	13.5	-0.2				
1960	11.9	8.5	7.1	8.4	9.8	5.6	1.8	-0.3	7.8	-1.9	-3.5			
1961	13.2	10.2	9.1	10.6	12.1	8.7	6.1	5.3	12.8	7.9	12.0	27.6		
1962	11.2	8.4	7.2	8.3	9.4	6.1	3.5	2.4	7.8	2.9	4.0	7.7	-12.1	
1963	11.2	8.5	7.5	8.5	9.5	6.6	4.4	3.5	8.3	4.4	5.6	8.7	-0.8	10.5
1964	11.8	9.4	8.5	9.5	10.5	8.0	6.1	5.6	10.0	7.1	8.5	11.6	6.2	15.4
1965	11.1	8.9	8.0	8.9	9.7	7.4	5.7	5.2	8.9	6.3	7.4	9.6	5.1	10.8
1966	9.8	7.5	6.6	7.3	8.0	5.7	4.0	3.4	6.5	3.9	4.5	5.9	1.5	4.9
1967	9.9	7.8	7.0	7.7	8.3	6.2	4.7	4.2	7.1	4.9	5.5	6.8	3.3	6.4
1968	10.2	8.2	7.5	8.2	8.8	6.9	5.6	5.2	7.9	6.0	6.6	7.9	5.1	8.0
1969	9.3	7.4	6.6	7.2	7.8	5.9	4.6	4.2	6.6	4.7	5.2	6.1	3.4	5.7
1970	8.3	6.4	5.6	6.2	6.6	4.8	3.5	3.0	5.1	3.3	3.6	4.3	1.8	3.5
1971	8.0	6.2	5.4	5.9	6.3	4.6	3.3	2.9	4.9	3.1	3.4	4.0	1.7	3.2
1972	8.5	6.8	6.1	6.6	7.0	5.5	4.3	4.0	5.9	4.4	4.7	5.4	3.4	4.9
1973	7.9	6.2	5.5	6.0	6.3	4.8	3.7	3.3	5.1	3.6	3.9	4.5	2.5	3.9
1974	6.2	4.5	3.8	4.1	4.4	2.9	1.7	1.3	2.8	1.3	1.4	1.7	-0.3	0.7
1975	6.3	4.7	4.1	4.4	4.7	3.2	2.1	1.7	3.2	1.7	1.9	2.2	0.4	1.4
1976	6.1	4.6	4.0	4.3	4.5	3.1	2.1	1.7	3.1	1.7	1.9	2.2	0.5	1.4
1977	6.0	4.5	3.9	4.2	4.4	3.1	2.1	1.7	3.0	1.8	1.9	2.2	0.6	1.5
1978	6.5	5.1	4.5	4.8	5.1	3.8	2.9	2.6	3.9	2.7	2.9	3.2	1.8	2.7
1979	7.5	6.1	5.6	5.9	6.2	5.1	4.2	4.0	5.3	4.2	4.5	4.9	3.6	4.6
1980	7.8	6.6	6.0	6.4	6.7	5.6	4.8	4.6	5.9	4.9	5.1	5.6	4.4	5.3

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
1981	6.8	5.6	5.1	5.4	5.6	4.5	3.7	3.5	4.7	3.7	3.8	4.2	3.0	3.8
1982	6.3	5.1	4.6	4.9	5.1	4.0	3.2	3.0	4.1	3.1	3.3	3.6	2.4	3.2
1983	6.9	5.7	5.2	5.5	5.7	4.7	4.0	3.8	4.8	3.9	4.1	4.5	3.4	4.1
1984	6.2	5.1	4.6	4.9	5.1	4.0	3.3	3.1	4.1	3.2	3.4	3.7	2.6	3.3
1985	6.4	5.3	4.9	5.1	5.3	4.4	3.7	3.5	4.5	3.6	3.8	4.1	3.1	3.7
1986	6.2	5.2	4.7	4.9	5.1	4.2	3.5	3.3	4.3	3.5	3.6	3.9	2.9	3.5
1987	6.0	4.9	4.5	4.7	4.9	4.0	3.3	3.1	4.0	3.2	3.3	3.6	2.7	3.3
1988	5.9	4.8	4.4	4.6	4.8	3.9	3.2	3.0	3.9	3.1	3.2	3.5	2.6	3.2
1989	6.0	5.0	4.5	4.8	4.9	4.1	3.5	3.3	4.1	3.4	3.5	3.8	2.9	3.5
1990	5.2	4.2	3.8	4.0	4.1	3.3	2.7	2.4	3.3	2.5	2.6	2.8	1.9	2.4
1991	5.2	4.2	3.7	3.9	4.1	3.2	2.6	2.4	3.2	2.5	2.6	2.8	1.9	2.4
1992	4.8	3.8	3.4	3.6	3.7	2.9	2.3	2.1	2.8	2.1	2.2	2.4	1.5	2.0
1993	5.2	4.3	3.9	4.1	4.2	3.4	2.9	2.7	3.4	2.7	2.8	3.0	2.3	2.7
1994	4.9	4.0	3.6	3.8	3.9	3.1	2.6	2.4	3.1	2.4	2.5	2.7	2.0	2.4
1995	5.0	4.1	3.7	3.8	4.0	3.2	2.7	2.5	3.2	2.5	2.6	2.8	2.1	2.5
1996	5.3	4.4	4.1	4.2	4.4	3.6	3.1	2.9	3.6	3.0	3.1	3.3	2.6	3.0
1997	5.4	4.5	4.1	4.3	4.4	3.7	3.2	3.1	3.8	3.2	3.2	3.4	2.8	3.2
1998	5.1	4.3	3.9	4.1	4.2	3.5	3.0	2.8	3.5	2.9	3.0	3.1	2.5	2.9
1999	5.5	4.7	4.4	4.5	4.7	4.0	3.5	3.4	4.0	3.5	3.6	3.7	3.1	3.5
2000	5.4	4.6	4.3	4.5	4.6	3.9	3.5	3.3	4.0	3.4	3.5	3.7	3.1	3.5
2001	5.0	4.2	3.9	4.0	4.1	3.5	3.0	2.8	3.5	2.9	3.0	3.1	2.5	2.9
2002	4.6	3.8	3.4	3.6	3.7	3.0	2.6	2.4	3.0	2.4	2.5	2.6	2.0	2.4
2003	4.9	4.1	3.8	3.9	4.0	3.4	2.9	2.8	3.4	2.9	2.9	3.1	2.5	2.9
2004	5.0	4.2	3.9	4.0	4.1	3.5	3.1	2.9	3.5	3.0	3.1	3.2	2.7	3.0
2005	5.2	4.5	4.2	4.3	4.4	3.8	3.4	3.3	3.8	3.4	3.4	3.6	3.0	3.4

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End Date	Start Date 1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977
1936														
1937														
1938														
1939														
1940														
1941														
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1960														
1961														
1962														
1963														
1964	20.3													
1965	10.9	1.5												
1966	3.1	-5.5	-12.6											
1967	5.4	0.4	-0.2	12.3										
1968	7.5	4.3	5.2	14.1	15.8									
1969	4.9	1.8	1.8	6.6	3.8	-8.2								
1970	2.5	-0.5	-0.9	2.0	-1.4	-10.0	-11.8							
1971	2.3	-0.3	-0.6	1.8	-0.8	-6.3	-5.4	1.0						
1972	4.3	2.3	2.4	5.0	3.5	0.4	3.3	10.8	20.5					
1973	3.2	1.3	1.3	3.2	1.7	-1.1	0.7	4.8	6.7	-7.0				
1974	-0.2	-2.2	-2.7	-1.4	-3.4	-6.6	-6.3	-4.9	-6.9	-20.6	-34.1			
1975	0.6	-1.2	-1.4	-0.2	-1.8	-4.3	-3.6	-2.0	-2.7	-10.5	-12.2	9.6		
1976	0.7	-0.9	-1.2	0.0	-1.4	-3.5	-2.9	-1.4	-1.9	-7.5	-7.6	5.6	1.6	
1977	0.8	-0.7	-0.9	0.2	-1.0	-2.9	-2.2	-0.9	-1.2	-5.5	-5.2	4.5	1.9	2.1
1978	2.1	0.8	0.8	1.9	1.0	-0.5	0.3	1.8	1.9	-1.2	0.0	8.5	8.2	11.5
1979	4.2	3.1	3.2	4.4	3.8	2.7	3.8	5.5	6.1	4.0	5.8	13.8	14.9	19.3
1980	5.0	4.1	4.2	5.5	4.9	4.0	5.1	6.8	7.5	5.8	7.7	14.6	15.6	19.1

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977
1981	3.5	2.5	2.5	3.5	2.9	1.9	2.7	4.1	4.4	2.6	3.8	9.2	9.1	10.6
1982	2.8	1.8	1.8	2.7	2.1	1.1	1.8	2.9	3.1	1.4	2.3	6.9	6.5	7.3
1983	3.8	3.0	3.0	4.0	3.4	2.6	3.4	4.5	4.8	3.4	4.5	8.7	8.6	9.6
1984	2.9	2.1	2.1	2.9	2.4	1.5	2.2	3.2	3.3	1.9	2.7	6.4	6.0	6.6
1985	3.4	2.6	2.7	3.5	3.0	2.2	2.9	3.9	4.1	2.8	3.6	7.1	6.8	7.4
1986	3.2	2.5	2.5	3.3	2.8	2.1	2.7	3.6	3.7	2.5	3.3	6.4	6.1	6.5
1987	3.0	2.2	2.2	2.9	2.5	1.8	2.3	3.2	3.3	2.1	2.8	5.6	5.3	5.6
1988	2.9	2.1	2.2	2.8	2.4	1.7	2.2	3.0	3.1	2.1	2.7	5.3	4.9	5.2
1989	3.2	2.5	2.5	3.2	2.8	2.2	2.7	3.4	3.6	2.6	3.2	5.7	5.4	5.7
1990	2.2	1.5	1.4	2.0	1.6	0.9	1.4	2.0	2.1	1.1	1.5	3.8	3.4	3.5
1991	2.1	1.5	1.5	2.0	1.6	1.0	1.4	2.0	2.1	1.1	1.6	3.6	3.3	3.4
1992	1.7	1.0	1.0	1.5	1.1	0.5	0.9	1.5	1.5	0.5	0.9	2.9	2.5	2.5
1993	2.5	1.8	1.9	2.4	2.0	1.5	1.9	2.5	2.5	1.7	2.1	4.0	3.7	3.8
1994	2.1	1.5	1.5	2.0	1.6	1.1	1.5	2.0	2.1	1.2	1.6	3.4	3.1	3.2
1995	2.2	1.7	1.7	2.2	1.8	1.3	1.6	2.2	2.2	1.4	1.8	3.5	3.2	3.3
1996	2.8	2.3	2.3	2.8	2.4	2.0	2.3	2.9	3.0	2.2	2.6	4.3	4.1	4.2
1997	3.0	2.4	2.5	3.0	2.6	2.2	2.6	3.1	3.2	2.5	2.9	4.5	4.2	4.4
1998	2.7	2.2	2.2	2.6	2.3	1.9	2.2	2.7	2.8	2.1	2.5	4.0	3.7	3.8
1999	3.3	2.8	2.9	3.4	3.1	2.7	3.0	3.5	3.6	3.0	3.4	4.9	4.7	4.8
2000	3.3	2.8	2.8	3.3	3.0	2.6	3.0	3.5	3.5	2.9	3.3	4.8	4.6	4.7
2001	2.7	2.2	2.3	2.7	2.4	2.0	2.3	2.8	2.8	2.2	2.5	3.9	3.7	3.8
2002	2.2	1.7	1.7	2.1	1.8	1.4	1.7	2.1	2.1	1.5	1.8	3.1	2.9	2.9
2003	2.7	2.2	2.2	2.6	2.4	2.0	2.3	2.7	2.7	2.2	2.5	3.7	3.5	3.6
2004	2.8	2.4	2.4	2.8	2.5	2.2	2.5	2.9	2.9	2.4	2.7	3.9	3.7	3.8
2005	3.2	2.8	2.8	3.2	3.0	2.6	2.9	3.4	3.4	2.9	3.2	4.4	4.3	4.3

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1936														
1937														
1938														
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1972														
1973														
1974														
1975														
1976														
1977														
1978	20.8													
1979	27.9	35.0												
1980	24.8	26.8	18.5											

Canadian Risk Premia Over Time Report

(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1981	12.7	10.0	-2.4	-23.4										
1982	8.3	5.2	-4.8	-16.4	-9.5									
1983	10.9	8.9	2.4	-3.0	7.2	23.8								
1984	7.2	5.0	-1.0	-5.9	-0.1	4.6	-14.6							
1985	8.0	6.2	1.4	-2.0	3.3	7.6	-0.5	13.6						
1986	7.0	5.3	1.1	-1.8	2.5	5.5	-0.6	6.3	-0.9					
1987	6.0	4.3	0.5	-2.1	1.5	3.7	-1.4	3.0	-2.2	-3.6				
1988	5.5	4.0	0.5	-1.7	1.4	3.2	-0.9	2.5	-1.2	-1.4	0.8			
1989	6.0	4.6	1.6	-0.3	2.6	4.3	1.1	4.2	1.9	2.8	6.0	11.2		
1990	3.6	2.2	-0.8	-2.7	-0.5	0.7	-2.6	-0.6	-3.5	-4.1	-4.3	-6.8	-24.9	
1991	3.5	2.1	-0.6	-2.3	-0.2	0.8	-2.1	-0.3	-2.6	-2.9	-2.8	-4.0	-11.5	1.8
1992	2.6	1.3	-1.3	-3.0	-1.1	-0.3	-3.0	-1.5	-3.7	-4.2	-4.3	-5.6	-11.1	-4.3
1993	3.9	2.8	0.5	-0.9	1.0	1.9	-0.3	1.3	-0.2	-0.1	0.5	0.4	-2.3	5.2
1994	3.2	2.1	-0.1	-1.4	0.3	1.1	-1.0	0.4	-1.1	-1.1	-0.7	-1.0	-3.4	2.0
1995	3.4	2.3	0.3	-0.9	0.7	1.5	-0.4	0.9	-0.4	-0.3	0.1	0.0	-1.9	2.7
1996	4.3	3.4	1.5	0.4	2.0	2.8	1.2	2.6	1.6	1.8	2.4	2.6	1.4	5.7
1997	4.5	3.6	1.9	0.9	2.4	3.2	1.7	3.0	2.1	2.4	3.0	3.2	2.2	6.1
1998	3.9	3.1	1.4	0.5	1.9	2.6	1.1	2.3	1.4	1.6	2.1	2.2	1.2	4.5
1999	4.9	4.2	2.7	1.8	3.2	4.0	2.7	3.9	3.2	3.5	4.1	4.4	3.7	6.9
2000	4.8	4.1	2.6	1.8	3.1	3.8	2.6	3.7	3.1	3.3	3.9	4.1	3.5	6.3
2001	3.8	3.1	1.6	0.8	2.0	2.7	1.5	2.4	1.7	1.9	2.3	2.4	1.7	4.1
2002	2.9	2.2	0.8	0.0	1.1	1.6	0.4	1.3	0.6	0.7	0.9	0.9	0.2	2.2
2003	3.7	3.0	1.6	0.9	2.0	2.6	1.5	2.3	1.7	1.9	2.2	2.3	1.7	3.7
2004	3.9	3.2	1.9	1.3	2.3	2.9	1.9	2.7	2.1	2.3	2.6	2.7	2.2	4.1
2005	4.4	3.8	2.6	2.0	3.0	3.6	2.7	3.5	3.0	3.2	3.6	3.7	3.3	5.1

Canadian Risk Premia Over Time Report

(Long Horizon Equity Risk Premium in Canadian Dollars)

End	Start Date													
Date	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1981														
1982														
1983														
1984														
1985														
1986														
1987														
1988														
1989														
1990														
1991														
1992	-10.3													
1993	7.0	24.3												
1994	2.0	8.2	-7.9											
1995	3.0	7.4	-1.1	5.7										
1996	6.5	10.8	6.2	13.3	20.9									
1997	6.8	10.3	6.8	11.6	14.6	8.4								
1998	4.8	7.4	4.0	6.9	7.3	0.6	-7.2							
1999	7.5	10.1	7.7	10.8	12.1	9.2	9.6	26.3						
2000	6.8	9.0	6.8	9.2	9.9	7.2	6.8	13.8	1.3					
2001	4.3	6.0	3.7	5.3	5.2	2.1	0.6	3.1	-8.5	-18.3				
2002	2.3	3.5	1.2	2.4	1.9	-1.3	-3.2	-2.2	-11.7	-18.2	-18.2			
2003	3.9	5.2	3.3	4.5	4.3	2.0	0.9	2.5	-3.4	-5.0	1.6	21.4		
2004	4.3	5.5	3.8	5.0	4.9	2.9	2.1	3.7	-0.9	-1.4	4.2	15.4	9.4	
2005	5.4	6.6	5.1	6.3	6.4	4.7	4.3	5.9	2.5	2.8	8.0	16.8	14.4	19.5

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1939	1940	1941	1942	1943	1944	1945	1946	1947	1948	1949	1950	1951	1952
1939	-11.3													
1940	-16.8	-22.3												
1941	-11.6	-11.8	-1.4											
1942	-6.0	-4.3	4.8	10.9										
1943	-1.5	1.0	8.7	13.7	16.6									
1944	0.5	2.9	9.2	12.7	13.5	10.5								
1945	5.2	7.9	14.0	17.8	20.1	21.9	33.4							
1946	5.2	7.5	12.5	15.3	16.4	16.3	19.2	5.1						
1947	4.4	6.3	10.4	12.4	12.7	11.7	12.1	1.4	-2.3					
1948	4.9	6.7	10.3	12.0	12.1	11.2	11.4	4.1	3.6	9.6				
1949	5.2	6.9	10.1	11.6	11.7	10.8	10.9	5.3	5.4	9.2	8.8			
1950	9.2	11.0	14.4	16.1	16.8	16.8	17.8	14.7	17.1	23.6	30.6	52.4		
1951	10.3	12.1	15.3	16.9	17.6	17.7	18.8	16.3	18.6	23.8	28.5	38.4	24.4	
1952	9.7	11.3	14.2	15.6	16.0	16.0	16.7	14.3	15.8	19.4	21.9	26.2	13.1	1.8
1953	9.0	10.4	12.9	14.1	14.4	14.2	14.6	12.3	13.3	15.9	17.2	19.2	8.2	0.1
1954	10.7	12.1	14.6	15.8	16.2	16.2	16.8	14.9	16.1	18.8	20.3	22.6	15.2	12.1
1955	11.3	12.7	15.0	16.2	16.6	16.6	17.1	15.5	16.6	19.0	20.4	22.3	16.3	14.2
1956	11.4	12.8	15.0	16.1	16.4	16.4	16.9	15.4	16.4	18.5	19.6	21.2	16.0	14.3
1957	9.5	10.6	12.6	13.4	13.6	13.4	13.6	12.0	12.6	14.1	14.6	15.3	10.0	7.6
1958	10.4	11.6	13.5	14.3	14.6	14.4	14.7	13.3	13.9	15.4	16.0	16.8	12.4	10.6
1959	10.0	11.1	12.8	13.6	13.8	13.6	13.8	12.4	13.0	14.2	14.6	15.2	11.1	9.4
1960	9.4	10.4	12.0	12.7	12.8	12.6	12.7	11.3	11.8	12.9	13.1	13.5	9.6	8.0
1961	9.9	10.9	12.5	13.2	13.3	13.1	13.2	12.0	12.4	13.5	13.8	14.2	10.7	9.4
1962	8.9	9.8	11.2	11.8	11.9	11.6	11.7	10.4	10.7	11.6	11.7	12.0	8.6	7.2
1963	8.9	9.8	11.2	11.7	11.8	11.5	11.6	10.4	10.7	11.5	11.6	11.8	8.7	7.4
1964	9.4	10.2	11.6	12.1	12.2	12.0	12.1	11.0	11.3	12.1	12.2	12.5	9.6	8.5
1965	9.1	9.9	11.2	11.7	11.7	11.5	11.6	10.5	10.8	11.5	11.6	11.8	9.1	8.0
1966	8.3	9.0	10.2	10.7	10.7	10.4	10.4	9.3	9.6	10.2	10.2	10.3	7.7	6.5
1967	8.5	9.2	10.3	10.8	10.8	10.5	10.5	9.5	9.7	10.3	10.3	10.4	8.0	6.9
1968	8.7	9.4	10.6	11.0	11.0	10.8	10.8	9.8	10.0	10.6	10.7	10.8	8.4	7.5
1969	8.2	8.8	9.9	10.3	10.3	10.0	10.0	9.1	9.2	9.8	9.8	9.8	7.6	6.6
1970	7.7	8.3	9.4	9.7	9.7	9.4	9.4	8.4	8.6	9.0	9.0	9.0	6.9	5.9
1971	7.6	8.1	9.1	9.5	9.4	9.2	9.1	8.2	8.3	8.8	8.7	8.7	6.6	5.7
1972	8.0	8.5	9.5	9.9	9.8	9.6	9.6	8.7	8.8	9.3	9.2	9.3	7.3	6.5
1973	7.5	8.1	9.0	9.3	9.3	9.0	9.0	8.1	8.2	8.6	8.6	8.6	6.7	5.9
1974	6.4	6.9	7.7	8.0	7.9	7.7	7.6	6.7	6.7	7.1	7.0	6.9	5.0	4.1
1975	6.4	6.9	7.7	8.0	7.9	7.6	7.5	6.7	6.7	7.1	7.0	6.9	5.1	4.3
1976	6.3	6.8	7.6	7.8	7.7	7.5	7.4	6.5	6.6	6.9	6.8	6.7	5.0	4.2
1977	6.0	6.4	7.2	7.4	7.4	7.1	7.0	6.2	6.2	6.5	6.4	6.3	4.6	3.8
1978	6.1	6.6	7.3	7.6	7.5	7.2	7.1	6.3	6.3	6.6	6.5	6.5	4.8	4.1
1979	6.9	7.3	8.1	8.3	8.3	8.0	8.0	7.2	7.3	7.6	7.5	7.5	5.9	5.3
1980	7.1	7.5	8.3	8.5	8.5	8.2	8.2	7.5	7.5	7.8	7.8	7.7	6.3	5.6
1981	6.4	6.8	7.5	7.7	7.7	7.4	7.3	6.6	6.7	6.9	6.8	6.8	5.3	4.7
1982	6.0	6.4	7.0	7.2	7.2	6.9	6.8	6.1	6.1	6.4	6.3	6.2	4.8	4.1
1983	6.3	6.7	7.4	7.6	7.5	7.3	7.2	6.5	6.6	6.8	6.7	6.7	5.3	4.7

Canadian Risk Premia Over Time Report

(Long Horizon Equity Risk Premium in U.S. Dollars)

End Date	Start Date 1939	1940	1941	1942	1943	1944	1945	1946	1947	1948	1949	1950	1951	1952
1984	5.8	6.1	6.8	7.0	6.9	6.6	6.5	5.9	5.9	6.1	6.0	5.9	4.6	4.0
1985	5.8	6.2	6.8	7.0	6.9	6.7	6.6	5.9	5.9	6.1	6.0	6.0	4.6	4.1
1986	5.7	6.0	6.7	6.8	6.7	6.5	6.4	5.8	5.8	6.0	5.9	5.8	4.5	3.9
1987	5.6	6.0	6.6	6.7	6.6	6.4	6.3	5.7	5.7	5.9	5.8	5.7	4.5	3.9
1988	5.7	6.0	6.6	6.8	6.7	6.5	6.4	5.8	5.8	6.0	5.9	5.8	4.6	4.1
1989	5.9	6.2	6.8	7.0	6.9	6.7	6.6	6.0	6.0	6.2	6.1	6.0	4.9	4.3
1990	5.3	5.6	6.2	6.3	6.2	6.0	5.9	5.3	5.3	5.5	5.4	5.3	4.1	3.6
1991	5.2	5.5	6.1	6.2	6.1	5.9	5.8	5.2	5.2	5.4	5.3	5.2	4.1	3.6
1992	4.8	5.1	5.6	5.7	5.6	5.4	5.3	4.7	4.7	4.9	4.8	4.7	3.5	3.0
1993	5.0	5.3	5.9	6.0	5.9	5.7	5.6	5.0	5.0	5.2	5.1	5.0	3.9	3.4
1994	4.7	5.0	5.5	5.6	5.5	5.3	5.2	4.7	4.6	4.8	4.7	4.6	3.5	3.0
1995	4.8	5.1	5.6	5.7	5.6	5.4	5.3	4.7	4.7	4.9	4.8	4.7	3.6	3.1
1996	5.1	5.3	5.8	6.0	5.9	5.7	5.6	5.0	5.0	5.2	5.1	5.0	4.0	3.5
1997	5.0	5.3	5.8	5.9	5.8	5.6	5.5	5.0	5.0	5.2	5.1	5.0	4.0	3.5
1998	4.7	5.0	5.5	5.6	5.5	5.3	5.2	4.7	4.7	4.8	4.7	4.6	3.6	3.2
1999	5.2	5.5	6.0	6.1	6.0	5.8	5.7	5.2	5.2	5.4	5.3	5.2	4.2	3.8
2000	5.1	5.4	5.8	5.9	5.9	5.7	5.6	5.1	5.1	5.2	5.1	5.1	4.1	3.7
2001	4.6	4.9	5.3	5.5	5.4	5.2	5.1	4.6	4.6	4.7	4.6	4.5	3.6	3.2
2002	4.3	4.5	5.0	5.1	5.0	4.8	4.7	4.2	4.2	4.3	4.2	4.1	3.2	2.8
2003	5.0	5.2	5.7	5.8	5.7	5.5	5.4	4.9	4.9	5.1	5.0	4.9	4.0	3.6
2004	5.2	5.4	5.8	6.0	5.9	5.7	5.6	5.2	5.2	5.3	5.2	5.1	4.3	3.9
2005	5.4	5.7	6.1	6.2	6.2	6.0	5.9	5.5	5.5	5.6	5.5	5.5	4.6	4.3

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966
1939														
1940														
1941														
1942														
1943														
1944														
1945														
1946														
1947														
1948														
1949														
1950														
1951														
1952														
1953	-1.7													
1954	17.2	36.1												
1955	18.4	28.4	20.7											
1956	17.4	23.8	17.6	14.5										
1957	8.7	11.3	3.1	-5.7	-26.0									
1958	12.1	14.8	9.5	5.8	1.5	28.9								
1959	10.5	12.6	7.9	4.6	1.3	15.0	1.1							
1960	8.8	10.3	6.0	3.0	0.1	8.8	-1.2	-3.5						
1961	10.2	11.7	8.2	6.1	4.5	12.1	6.4	9.1	21.8					
1962	7.7	8.7	5.3	3.1	1.2	6.7	1.1	1.1	3.5	-14.9				
1963	7.9	8.9	5.9	4.0	2.5	7.3	2.9	3.4	5.7	-2.3	10.2			
1964	9.0	10.0	7.4	5.9	4.8	9.2	5.9	6.9	9.5	5.4	15.6	21.0		
1965	8.4	9.3	6.8	5.5	4.4	8.3	5.3	6.0	7.9	4.4	10.9	11.2	1.4	
1966	6.9	7.5	5.2	3.8	2.7	5.9	3.0	3.2	4.4	0.9	4.8	3.1	-5.9	-13.3
1967	7.3	7.9	5.7	4.5	3.6	6.5	4.0	4.4	5.5	2.8	6.4	5.4	0.2	-0.4
1968	7.9	8.5	6.5	5.4	4.7	7.5	5.3	5.8	6.9	4.8	8.1	7.7	4.4	5.3
1969	6.9	7.4	5.5	4.5	3.7	6.2	4.1	4.4	5.3	3.2	5.8	5.0	1.8	2.0
1970	6.2	6.6	4.8	3.7	3.0	5.2	3.2	3.4	4.1	2.1	4.3	3.4	0.5	0.3
1971	5.9	6.4	4.6	3.6	2.9	5.0	3.1	3.3	3.9	2.1	4.0	3.2	0.7	0.6
1972	6.7	7.2	5.6	4.7	4.0	6.0	4.4	4.7	5.4	3.9	5.7	5.2	3.3	3.5
1973	6.1	6.4	4.9	4.0	3.4	5.2	3.6	3.8	4.4	2.9	4.6	4.0	2.1	2.2
1974	4.3	4.5	3.0	2.0	1.3	2.9	1.3	1.3	1.7	0.1	1.4	0.6	-1.5	-1.8
1975	4.4	4.6	3.1	2.3	1.6	3.2	1.6	1.7	2.0	0.6	1.8	1.1	-0.7	-0.9
1976	4.3	4.5	3.1	2.3	1.7	3.1	1.7	1.7	2.0	0.7	1.8	1.2	-0.5	-0.6
1977	3.9	4.1	2.7	1.9	1.3	2.7	1.3	1.3	1.6	0.3	1.3	0.7	-0.9	-1.1
1978	4.2	4.4	3.1	2.3	1.8	3.1	1.8	1.8	2.1	1.0	2.0	1.4	0.0	-0.1
1979	5.4	5.7	4.4	3.8	3.3	4.6	3.5	3.6	4.0	3.0	4.0	3.6	2.5	2.6
1980	5.8	6.0	4.9	4.3	3.8	5.1	4.0	4.2	4.6	3.7	4.7	4.4	3.3	3.4
1981	4.8	5.0	3.9	3.2	2.8	4.0	2.9	3.0	3.3	2.3	3.2	2.9	1.8	1.8
1982	4.2	4.4	3.3	2.6	2.2	3.3	2.2	2.3	2.5	1.6	2.4	2.0	1.0	1.0
1983	4.8	5.0	3.9	3.3	2.9	4.0	3.0	3.1	3.4	2.6	3.4	3.0	2.1	2.1

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966
1984	4.0	4.2	3.1	2.5	2.1	3.1	2.2	2.2	2.4	1.6	2.3	2.0	1.0	1.0
1985	4.1	4.3	3.3	2.7	2.3	3.3	2.3	2.4	2.6	1.8	2.6	2.2	1.3	1.3
1986	4.0	4.2	3.2	2.6	2.2	3.2	2.3	2.3	2.5	1.8	2.5	2.1	1.3	1.3
1987	4.0	4.1	3.2	2.6	2.2	3.2	2.3	2.3	2.5	1.8	2.5	2.1	1.3	1.3
1988	4.1	4.3	3.4	2.8	2.5	3.4	2.5	2.6	2.8	2.1	2.8	2.5	1.7	1.7
1989	4.4	4.6	3.7	3.2	2.8	3.7	2.9	3.0	3.2	2.5	3.2	2.9	2.2	2.2
1990	3.6	3.8	2.9	2.4	2.0	2.9	2.0	2.1	2.3	1.6	2.2	1.9	1.1	1.1
1991	3.6	3.7	2.9	2.4	2.0	2.8	2.1	2.1	2.3	1.6	2.2	1.9	1.2	1.2
1992	3.0	3.2	2.3	1.8	1.4	2.2	1.4	1.5	1.6	1.0	1.5	1.2	0.5	0.4
1993	3.4	3.6	2.7	2.3	1.9	2.7	2.0	2.0	2.2	1.5	2.1	1.8	1.1	1.1
1994	3.0	3.2	2.3	1.9	1.5	2.3	1.5	1.6	1.7	1.1	1.6	1.3	0.7	0.6
1995	3.2	3.3	2.5	2.0	1.7	2.5	1.7	1.8	1.9	1.3	1.8	1.5	0.9	0.9
1996	3.6	3.7	2.9	2.5	2.2	2.9	2.2	2.3	2.4	1.9	2.4	2.1	1.5	1.5
1997	3.6	3.7	2.9	2.5	2.2	2.9	2.3	2.3	2.5	1.9	2.4	2.2	1.6	1.6
1998	3.2	3.3	2.6	2.2	1.9	2.5	1.9	1.9	2.0	1.5	2.0	1.7	1.2	1.2
1999	3.9	4.0	3.3	2.9	2.6	3.3	2.7	2.7	2.9	2.4	2.8	2.6	2.1	2.1
2000	3.7	3.8	3.1	2.8	2.5	3.2	2.5	2.6	2.7	2.2	2.7	2.5	2.0	2.0
2001	3.2	3.3	2.6	2.2	1.9	2.6	1.9	2.0	2.1	1.6	2.0	1.8	1.3	1.3
2002	2.8	2.9	2.2	1.8	1.5	2.1	1.5	1.5	1.6	1.1	1.5	1.3	0.8	0.8
2003	3.7	3.8	3.1	2.7	2.5	3.1	2.5	2.6	2.7	2.2	2.7	2.5	2.0	2.0
2004	3.9	4.0	3.4	3.0	2.8	3.4	2.9	2.9	3.1	2.6	3.0	2.9	2.4	2.4
2005	4.3	4.4	3.8	3.5	3.2	3.8	3.3	3.4	3.5	3.1	3.5	3.3	2.9	3.0

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
1939														
1940														
1941														
1942														
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1963														
1964														
1965														
1966														
1967	12.6													
1968	14.6	16.7												
1969	7.0	4.3	-8.2											
1970	3.7	0.7	-7.3	-6.4										
1971	3.3	1.0	-4.2	-2.2	1.9									
1972	6.3	5.1	2.2	5.6	11.6	21.3								
1973	4.4	3.1	0.3	2.5	5.4	7.1	-7.1							
1974	-0.4	-2.2	-5.4	-4.8	-4.4	-6.5	-20.4	-33.8						
1975	0.5	-1.1	-3.6	-2.8	-2.1	-3.2	-11.3	-13.4	6.9					
1976	0.6	-0.7	-2.9	-2.1	-1.4	-2.0	-7.9	-8.2	4.6	2.4				
1977	0.1	-1.2	-3.2	-2.6	-2.0	-2.7	-7.5	-7.6	1.2	-1.7	-5.8			
1978	1.0	0.0	-1.7	-1.0	-0.3	-0.7	-4.3	-3.8	3.7	2.7	2.8	11.4		
1979	3.8	3.0	1.8	2.8	3.8	4.1	1.6	3.0	10.4	11.3	14.2	24.2	37.1	
1980	4.6	4.0	3.0	4.0	5.0	5.4	3.4	4.9	11.3	12.2	14.6	21.5	26.5	15.9
1981	2.8	2.1	1.0	1.8	2.5	2.5	0.5	1.4	6.4	6.4	7.1	10.4	10.0	-3.5
1982	1.8	1.1	0.0	0.6	1.2	1.2	-0.8	-0.2	4.0	3.6	3.8	5.8	4.4	-6.5
1983	3.0	2.4	1.5	2.2	2.9	2.9	1.3	2.1	6.1	6.0	6.5	8.5	7.9	0.7

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
1984	1.8	1.2	0.2	0.7	1.2	1.2	-0.5	0.1	3.5	3.1	3.2	4.5	3.4	-3.4
1985	2.1	1.5	0.6	1.2	1.7	1.6	0.1	0.7	3.9	3.6	3.7	4.9	3.9	-1.6
1986	2.0	1.4	0.6	1.1	1.6	1.6	0.1	0.7	3.6	3.3	3.4	4.4	3.5	-1.3
1987	2.0	1.5	0.7	1.2	1.6	1.6	0.3	0.8	3.5	3.2	3.3	4.2	3.4	-0.8
1988	2.4	1.9	1.1	1.6	2.1	2.1	0.9	1.4	3.9	3.7	3.8	4.7	4.0	0.3
1989	2.9	2.5	1.8	2.3	2.7	2.8	1.7	2.2	4.6	4.5	4.6	5.5	5.0	1.8
1990	1.7	1.3	0.6	1.0	1.3	1.3	0.2	0.6	2.8	2.5	2.5	3.2	2.5	-0.7
1991	1.8	1.3	0.6	1.0	1.4	1.4	0.3	0.7	2.7	2.5	2.5	3.1	2.4	-0.4
1992	1.0	0.5	-0.2	0.2	0.5	0.4	-0.6	-0.3	1.6	1.3	1.2	1.7	1.0	-1.8
1993	1.7	1.2	0.6	1.0	1.3	1.3	0.3	0.7	2.5	2.3	2.3	2.8	2.2	-0.3
1994	1.1	0.7	0.1	0.4	0.7	0.7	-0.3	0.0	1.7	1.5	1.4	1.8	1.2	-1.2
1995	1.4	1.0	0.4	0.7	1.0	1.0	0.1	0.4	2.1	1.8	1.8	2.2	1.7	-0.5
1996	2.0	1.7	1.1	1.5	1.8	1.8	0.9	1.3	2.9	2.7	2.7	3.2	2.7	0.7
1997	2.1	1.7	1.2	1.6	1.8	1.8	1.1	1.4	2.9	2.7	2.8	3.2	2.8	0.9
1998	1.6	1.2	0.7	1.0	1.3	1.3	0.5	0.8	2.3	2.1	2.0	2.4	2.0	0.1
1999	2.6	2.3	1.8	2.1	2.4	2.4	1.7	2.1	3.5	3.4	3.4	3.8	3.5	1.8
2000	2.4	2.1	1.7	2.0	2.3	2.3	1.6	1.9	3.3	3.1	3.2	3.6	3.2	1.6
2001	1.7	1.4	0.9	1.2	1.5	1.4	0.8	1.0	2.3	2.1	2.1	2.5	2.1	0.5
2002	1.2	0.9	0.4	0.7	0.9	0.8	0.2	0.4	1.6	1.4	1.4	1.7	1.3	-0.3
2003	2.4	2.1	1.7	2.0	2.3	2.3	1.7	2.0	3.2	3.1	3.1	3.4	3.1	1.7
2004	2.8	2.6	2.2	2.5	2.7	2.8	2.2	2.5	3.7	3.6	3.6	4.0	3.7	2.4
2005	3.4	3.1	2.8	3.1	3.3	3.4	2.8	3.1	4.3	4.2	4.3	4.7	4.4	3.2

Canadian Risk Premia Over Time Report

(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
1939														
1940														
1941														
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1976														
1977														
1978														
1979														
1980														
1981	-22.8													
1982	-17.8	-12.7												
1983	-4.4	4.8	22.3											

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date													
Date	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
1984	-8.2	-3.3	1.4	-19.6										
1985	-5.1	-0.6	3.4	-6.1	7.4									
1986	-4.2	-0.4	2.6	-4.0	3.9	0.3								
1987	-3.2	0.0	2.6	-2.4	3.4	1.4	2.4							
1988	-1.6	1.4	3.8	0.1	5.0	4.2	6.1	9.8						
1989	0.2	3.1	5.3	2.5	6.9	6.8	8.9	12.2	14.5					
1990	-2.3	-0.1	1.5	-1.4	1.6	0.4	0.4	-0.2	-5.2	-25.0				
1991	-1.9	0.2	1.6	-1.0	1.7	0.7	0.8	0.4	-2.8	-11.4	2.2			
1992	-3.3	-1.5	-0.4	-2.9	-0.9	-2.0	-2.4	-3.4	-6.7	-13.8	-8.2	-18.5		
1993	-1.6	0.2	1.4	-0.7	1.4	0.6	0.7	0.4	-1.5	-5.5	1.0	0.4	19.4	
1994	-2.4	-0.8	0.2	-1.8	-0.1	-0.9	-1.0	-1.5	-3.4	-7.0	-2.5	-4.1	3.2	-13.0
1995	-1.6	-0.1	0.8	-1.0	0.7	0.1	0.0	-0.2	-1.7	-4.4	-0.3	-0.9	5.0	-2.2
1996	-0.3	1.2	2.2	0.7	2.4	1.9	2.1	2.0	1.1	-0.9	3.2	3.4	8.8	5.3
1997	0.0	1.4	2.3	0.9	2.5	2.1	2.2	2.2	1.4	-0.3	3.3	3.4	7.8	5.0
1998	-0.8	0.5	1.4	0.0	1.4	0.9	0.9	0.8	-0.1	-1.7	1.2	1.1	4.3	1.3
1999	1.1	2.4	3.3	2.1	3.5	3.3	3.5	3.6	3.0	1.8	4.8	5.2	8.5	6.7
2000	0.9	2.1	3.0	1.8	3.2	2.9	3.1	3.1	2.6	1.5	4.1	4.3	7.2	5.4
2001	-0.3	0.9	1.6	0.4	1.6	1.3	1.3	1.2	0.6	-0.6	1.6	1.6	3.8	1.9
2002	-1.0	0.0	0.7	-0.5	0.6	0.2	0.2	0.0	-0.7	-1.9	0.1	-0.1	1.7	-0.2
2003	1.1	2.2	2.9	1.9	3.0	2.8	2.9	3.0	2.5	1.7	3.7	3.8	5.9	4.5
2004	1.8	2.9	3.6	2.7	3.8	3.6	3.8	3.9	3.5	2.8	4.7	4.9	6.9	5.8
2005	2.7	3.7	4.4	3.6	4.7	4.6	4.8	4.9	4.7	4.0	6.0	6.2	8.2	7.2

Canadian Risk Premia Over Time Report
(Long Horizon Equity Risk Premium in U.S. Dollars)

End	Start Date										
Date	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1984											
1985											
1986											
1987											
1988											
1989											
1990											
1991											
1992											
1993											
1994											
1995	8.7										
1996	14.5	20.3									
1997	10.9	12.1	3.8								
1998	4.9	3.6	-4.7	-13.3							
1999	10.7	11.2	8.1	10.3	33.9						
2000	8.5	8.5	5.5	6.1	15.8	-2.4					
2001	4.0	3.2	-0.2	-1.2	2.8	-12.7	-23.0				
2002	1.4	0.3	-3.0	-4.4	-2.2	-14.2	-20.1	-17.1			
2003	6.5	6.2	4.2	4.2	7.7	1.2	2.4	15.1	47.2		
2004	7.6	7.5	5.9	6.2	9.5	4.6	6.3	16.1	32.7	18.2	
2005	9.1	9.1	7.8	8.4	11.4	7.7	9.7	17.9	29.6	20.7	23.3

CME, CCC, SEC, VECC INTERROGATORY #3

INTERROGATORY

E - Cost of Capital
Issue E3: Is the proposal to use the Board's formula to calculate return on equity appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

Appendix A discusses ROE analysis: Leverage adjustments.

a) Please confirm that the Hamada adjustment underlying the graph on page A-6 flows from a classical tax system where the shareholders capture the tax advantage from debt financing, that is, the value of the levered firm is equal to that of an unlevered firm plus the M&M 1963 tax shield value from debt.

b) Please comment on the relevance of the adjustment in the context of the Canadian tax system.

c) Please comment on the validity of the equation on page A-7 for Canadian regulated utilities.

RESPONSE

a) Confirmed. The Hamada equation stems from the fact that interest expense is deductible in arriving at taxable income.

b) This adjustment is relevant for any tax system that provides for deductibility of interest expense before arriving at taxable income, as is the case in Canada. Canada provides that interest expense is deductible for tax purposes as long as it i) represents compensation for the use of money by the lender; ii) is referable (usually by percentage) to a principal sum; and iii) accrues on a daily basis. Interest is a capital expenditure and is deductible, provided that the amount is pursuant to a legal

Witnesses: J. Coyne
J. Lieberman
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obligation and the amount must be reasonable. Further, borrowed money must be used either directly or indirectly for earning income from business or property.[1]

c) The equation on page A-7 is valid for taxable Canadian regulated utilities that have financed a portion of their income producing operations with debt. Because utilities recover taxes paid through rates, tax benefits are principally passed on to the ratepayers. According to Roger A. Morin Phd, New Regulatory Finance, regulated firms may benefit less than non-regulated firms for this reason, hence the Hamada equation may underestimate the cost of equity for the regulated utility. According to Dr. Morin, there is a range of capital structures over which the average cost of capital does not change materially. Within this range, an increase in the debt ratio will result in an increase in both the cost of debt and the cost of equity, but the overall cost of capital will not change measurably. Dr. Morin estimates that regulated utilities do benefit somewhat from the tax shield as the impact on the leverage/cost of equity relationship will depend on the exact manner in which regulators pass through the tax savings from debt financing to ratepayers.[2] Concentric has used the Hamada equation to adjust equity returns for changes in leverage. The equation assumes that equity shareholders will realize some benefit from the associated tax savings. The resulting levered cost of equity estimate is somewhat moderated by the tax benefit which yields a more conservative levered cost of equity estimate versus that which would be computed under an assumed no tax scenario.

[1] Manu Kakkar, Canadian General Accountants, Profession- Tax Strategy, *Interest Deductibility - A brief review of the direct and indirect use tests*. (NOV-DEC 2008 ISSUE)

[2] Roger A. Morin, Phd., New Regulatory Finance, Public Utilities Reports, Inc. (2006) at 465-466.

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