Pollution Probe Interrogatory #1

Ref: Ex. C2-T1-S1

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

If the Board does not approve OPG's proposal to recover 25% of its nuclear revenues via a capacity charge, please provide your recommended capital structure for OPG's regulated assets. Please also justify your response.

Response

Historical variances from forecast in production from 2005 - 2007 indicate that the average short-fall has been approximately 2.5 TWh (shortfalls of approximately 0.2, 2.5 and 5 TWh respectively in 2005, 2006 and 2007); the standard deviation of the three short-falls is also approximately 2.5%. With the proposed fixed payment of 25% of the nuclear revenue requirement, a 2.5 TWh reduction from forecast nuclear production would reduce total regulated earnings (assuming a 34% tax rate) by approximately $62 million and the ROE (based on 2009 regulated equity) by approximately 1.5%.

If the fixed payment were not approved, the same reduction from forecast production would reduce total regulated earnings by approximately $84 million, a reduction in the regulated ROE of approximately 2%. The corresponding reductions at short-falls of 0.2 and 5 TWh result in reductions to the ROE of approximately 0.8% and 3% with the fixed payment and 1% and 4% without the fixed payment.

The standard deviations of the reduction in ROEs under the three scenarios with and without the fixed payment are approximately 1.1% and 1.5% respectively, a difference of 0.4%. The increase in the potential variability of returns would in principle increase the cost of capital, but there is no documented empirical relationship between the variability in earned returns on book value and the cost of capital. In Ms. McShane's judgment, the increase in the required ROE could be approximately half the increase in the variability, i.e., approximately 25 basis points. In the alternative, a 25 basis point increase in return on equity could be reflected in the capital structure, resulting in an equity ratio of approximately 60%.

Pollution Probe Interrogatory #2

Ref: Ex. C2-T1-S1

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Assuming the Board determines that OPG's regulated nuclear and hydro-electric businesses should have two distinct stand-alone capital structures, please state your recommended capital structures for each of these two businesses. With respect to the nuclear business, please state your recommended capital structure assuming that:

(a) the Board approves OPG's proposal to recover 25% of its nuclear revenues via a capacity charge; and

(b) the Board does not approve OPG's proposal to recover 25% of its nuclear revenues via a capacity charge.

Please also justify all of your responses.

Response

The determination of stand-alone capital structures for the nuclear and hydroelectric businesses requires significant judgment for two reasons:

(1) There are no direct proxies for the regulated hydroelectric business. There are no publicly traded electric utilities in Canada that have significant hydroelectric generation. All of the major hydroelectric intensive utilities are government-owned. FortisBC, the only investor-owned utility with significant hydroelectric generation, is a small subsidiary of a larger company with a broad base of utility assets and real estate properties. While Brookfield Asset Management owns significant hydroelectric generation assets, directly and through its ownership interest in Great Lakes Hydro Income Fund, the hydroelectric assets are a relatively small piece of the business.

In the U.S., hydroelectric generation is a significantly less important source of generation than in Canada. In 2005, it accounted for less than 7% of total electricity generated. The proportion of total electricity generated by conventional hydroelectric facilities has been declining since the mid-1990s. Further, just under 25% of hydroelectricity generation capacity is owned by investor-owned

utilities; federal government agencies own over 50% of the total capacity, no trading information is available for that capacity. Of the investor-owned utilities that own hydroelectric generation capacity, there are only eight that have significant hydroelectric generation. Two are non-investment grade, one has only been publicly traded since mid-2006, four have very minor proportions of total assets devoted to hydroelectric generation, leaving only one company (IdaCorp) with a significant portion (approximately 25%) of total assets devoted to hydroelectric generation. In sum, there are insufficient hydroelectric-specific data from which to reliably estimate a stand-alone cost of equity for hydroelectric generation operations.

(2) An initial attempt (using data ending 2005) to quantitatively isolate the cost of capital for the nuclear business using samples of publicly-traded utilities produced results that were directionally reasonable (a risk premium based on the CAPM of approximately 2.0-2.5% higher than that applicable to the benchmark utility sample), but given the small sample of utilities used to represent the nuclear operations, the relatively small difference between the betas for the nuclear-intensive companies and the other-generation intensive companies, and thus the sensitivity of the results to small changes in beta, as well as other potential explanations for the beta differences between the nuclear-intensive and other generation-intensive companies, and the derived nuclear-only and other generation-only betas (e.g., regulatory framework), the results are not empirically robust. An update of the analysis using data ending 2006 produced results that were inconsistent with the qualitative business risk analysis, which, for nuclear operations, include the technical challenges and the high proportion of fixed costs. (See also discussion of nuclear risks as they pertain to OPG at pages 68 - 77 of Ms. McShane's report Ex. C2-T1-S1). Specifically, the updated analysis indicated that the cost of capital for nuclear operations was lower than for the composite of other generation (hydroelectric, fossil, and renewable resources).

In light of these results and considerations, the estimation of separate costs of capital (capital structures and ROEs) for the nuclear and hydroelectric businesses requires significant judgment. Ms. McShane's analysis of OPG's composite regulated operations supported a reasonable return on equity for OPG's composite regulated operations of 11.75% to 12.0% at a 45% common equity ratio, or a common equity ratio of 55%-60% (mid-point of 57.5%) at the benchmark ROE of 10.5%. If the intuitively reasonable 2.25% risk premium initially estimated for the nuclear business (at the average common equity ratio of the companies in the samples) were applied to the 10.5% benchmark ROE, the ROE for the nuclear business would be approximately 12.75%. The corresponding common equity ratio for the nuclear business at the benchmark ROE of 10.5% would be close to 65%.

The returns and capital structures are effectively a weighted average of the costs of capital of the hydroelectric and nuclear operations. The nuclear assets represent approximately 45% of OPG's total regulated assets and the hydroelectric assets comprise the remaining 55% (as measured by forecast 2009 rate base). The application

of a 45% weighting to the nuclear operations at a common equity ratio of 65% and an ROE of 10.5% to the common equity ratio of 57.5% and the same 10.5% ROE results in a common equity ratio for the hydroelectric operations of approximately 50%.

Alternatively, using the regulated hydroelectric operations as the point of departure, given its business risk profile, Ms. McShane's best estimate of the appropriate common equity ratio at the benchmark ROE would be 45%, equal to that of the benchmark (low risk) U.S. utility sample. The low risk U.S. utility sample used to establish the benchmark return on equity is largely a "wires" sample (average generation component, as percent of total assets, of less than 10%). Inherently, generation operations are more risky than "wires" operations, as they are not a natural monopoly and they face higher operating/physical risks. On the spectrum of generation technologies, hydroelectric operations are at the lower end of the scale (i.e., less risky than nuclear and fossil). Given the primarily baseload nature of the regulated hydroelectric operations and the mitigation of the inherent hydrology risks of OPG's regulated hydroelectric operations via the variance account, Ms. McShane views their level of business risk as similar to that of the benchmark low risk utility sample. Thus, a reasonable capital structure for the stand-alone hydroelectric operations on that basis would be similar to that of the sample, that is, a common equity ratio of approximately 45% at the benchmark ROE of 10.5%. With a return on equity for the composite regulated operations of 11.75% to 12.0% and a return on equity of 10.5% for the hydroelectric operations (both at a 45% common equity ratio), the implied return on equity for the nuclear operations is approximately 13.5% (11.875% = .55(10.5%) +.45x). Translating the indicated ROE of 13.5% on a common equity ratio of 45% to the indicated common equity ratio compatible with the benchmark ROE of 10.5% results in an equity ratio of close to 75% for nuclear operations.

The combination of the two approaches, while they are based on a number of assumptions and are subject to significant judgment, produce a range of results that are not unreasonable, that is, a range of common equity ratios of 45%-50% for the hydroelectric operations and 65%-75% for the nuclear operations at the 10.5% benchmark ROE. In Ms. McShane's view, the range of indicated equity ratios for the hydroelectric operations, in conjunction with the benchmark ROE is reasonable. With regard to the nuclear operations, an equity ratio of 65% to 75%, while common for unregulated companies, may be considered higher than necessary for a regulated business, even one with the risks faced by the nuclear operations. If the OEB were to deem separate costs of capital for the nuclear and hydroelectric businesses, the upper end of the recommended range of common equity ratios for the total prescribed assets (60%) would be reasonable, combined with an ROE in the approximate range of 11.0% to 11.5%, assuming that the fixed payment is approved. In the case the fixed payment is not approved, please see response to L-12-4.

Pollution Probe Interrogatory #3

Ref: Ex. C2-T1-S1

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

If the Board does not approve OPG's proposal to recover 25% of its nuclear revenues via a capacity charge, please provide your recommended return on equity for OPG's regulated assets. Please also justify your response.

Response

As noted at Ex. C2-T1-S1, pages 21 and 22 of Ms. McShane's testimony, the ROE recommended for OPG was the estimated "benchmark" ROE, with the business risks of the regulated operations reflected in the capital structure. Thus, there would be no change in the recommended ROE if the Board does not approve the proposed capacity charge. The change would be made to the capital structure.

See response to interrogatory L-12-1.

Pollution Probe Interrogatory #4

Ref: Ex. C2-T1-S1

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Assuming the Board determines that OPG's regulated nuclear and hydro-electric businesses should have two distinct returns on equity, please state your recommended returns on equity for each of these two businesses. With respect to the nuclear business, please state your recommended return on equity assuming that:

(a) the Board approves OPG's proposal to recover 25% of its nuclear revenues via a capacity charge; and

(b) the Board does not approve OPG's proposal to recover 25% of its nuclear revenues via a capacity charge.

Please also justify all of your responses.

Response

As per the analysis in L-12-1 and the response to L-12-2, if the Board were to decide that it is appropriate to deem separate capital structures and/or set separate ROEs, Ms. McShane would recommend an ROE of approximately 11.0-11.5% with a common equity ratio of 60% assuming the fixed payment is approved. If it is not approved, she would recommend the same capital structure as indicated in response to L-12-2 (60% equity); the resulting ROE could be approximately 50 basis points higher than in the absence of the fixed payment (11.5%-12.0%), since the variability identified in L-12-1 is attributable to the nuclear operations, which account for approximately 45% of the total prescribed assets.

Pollution Probe Interrogatory #5

Ref: Ex. E2-T1-S1, Table 1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Please provide the annual capacity utilization rates of each of OPG's nuclear reactors for every year from their in-service dates to 2007 inclusive.

Response

The table below provides unit capability factor percentages for each of OPG's nuclear units for the period 2005 - 2007. The data are provided as `Unit Capability Factor' consistent with the manner in which OPG has represented unit output in its evidence (please see definition provided at Ex. E2-T1-S1, page 23). `Annual capacity utilization rates' is not a term OPG uses to track generation output.

OPG declines to provide historical information prior to 2005 for the reasons given in L-12-6.

ONTARIO POWER GENERATION NUCLEAR
Unit Capability Factor (%)

Unit	2005	2006	2007
Darlington			
Unit 1	96.1	83.5	97.0
Unit 2	79.2	98.6	83.0
Unit 3	98.7	72.7	94.2
Unit 4	85.8	97.1	81.0
Pickering A			
Unit 1	92.7	77.3	38.9
Unit 4	66.5	66.3	43.7
Pickering B			
Unit 5	53.3	89.7	57.7
Unit 6	64.3	86.5	71.8
Unit 7	97.9	59.2	82.0
Unit 8	94.5	64.9	87.3

Pollution Probe Interrogatory #6

Ref: Ex. B1-T1-S1, Table 1

Issue Number: 5.4
Issue: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Interrogatory

Please provide the gross plant (at cost) and accumulated depreciation of the Niagara Plant Group and the Saunders Generating Station as of March 31, 1999. Please also provide a break-out of the major changes (i.e. $100 million or more) to the gross plant (at cost) and accumulated depreciation of the Niagara Plant Group and the Saunders Generating Station between March 31, 1999 and March 31, 2008.

Response

Historical information for 2005 – 2007 and forecast information for 2008 and 2009 is provided in the tables in Ex. B2-T1-S1 in the filing, and explanations of changes are provided in Ex. B1-T1-S1 consistent with the OEB report: "Filing Guidelines for Ontario Power Generation", EB-2006-0064, July 27, 2007.

Historical information for the period from 1999 to 2004 is not provided. In issuing the filing guidelines for OPG's prescribed facilities, the OEB stated:

> *OPG, along with some other stakeholders, submitted that data should not be required for 2004 or earlier years, as proposed in staff's discussion paper. As the current payment regime was implemented in April 2005, these stakeholders questioned the relevance of 2004 and pre-2004 information. OPG, for its part, also indicated that providing the information would be a significant burden for it. The Board has accepted these submissions, and has not included information relating to 2004 or earlier years in the Filing Guidelines.*

Setting Payment Amounts for Ontario Power Generation Inc.'s Prescribed Generation Assets. Filing Guidelines, EB-2006-0064, July 27, 2007, page 3.

The filing guidelines themselves state:

> *In addition, OPG should meet the following guidelines in preparing its filing:*
>
> - *Five years of data (2005 - 2009) should be submitted*.

Filing Guidelines for Ontario Power Generation, EB-2006-0064, July 27, 2007, page 10.

The OEB has, therefore, already made a determination that data from before 2005 is not relevant. OPG has complied with the findings and directions of the OEB.

Moreover, O. Reg. 53/05 requires the OEB to accept the asset and liability values from the most recent audited financial statements (2007). This is a further reason why historical data on asset values and depreciation for the period prior to regulation are not relevant to the determination of payment amounts in the test period.

Information on actual results for the period from January 1, 2008 to March 31, 2008 will be prepared as OPG completes its Quarterly Financial Statements for the first quarter of 2008, and will be made public after they are approved by OPG's Board of Directors.

Pollution Probe Interrogatory #7

Ref: Ex. B1-T1-S1, Table 1

Issue Number: 5.4
Issue: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Interrogatory

Please provide a break-out of OPG's capital expenditures at the Niagara Plant Group and the Saunders Generating Station for each year from 1999 to 2008 inclusive.

Response

Historical information for 2005 - 2007 and forecast information for 2008 and 2009 is provided in Ex. D1-T1-S1.

OPG declines to provide historical information for 1999 through 2004 for the reasons given in L-12-6.

Pollution Probe Interrogatory #8

Ref: Ex. E2-T1-S1, Table 1

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

Please forecast Ontario's incremental cost of obtaining replacement electricity supplies in 2008 and 2009 under each of the following scenarios:

(a) the output of OPG's nuclear business is 25% less than forecast; and

(b) the output of OPG's nuclear business is 50% less than forecast.

Please also state all of your assumptions and show all of your calculations.

Response

Assumptions:

- OPG 2008-2010 Business Plan is the base case.
- In each year, 2 alternative scenarios were prepared using the same assumptions as the 2008 - 2010 Business Plan except that OPG Nuclear Generation was reduced by 25% and 50% respectively from the plan.
- ProSym, a multi-area power market simulation tool sold by Ventyx, was used to simulate the alternative scenarios for Ontario generation in the context of the broader interconnected power market.
- Ontario's incremental cost of replacement electricity is calculated as the difference in the value of the generation for Ontario Primary Demand between the Base Case and the alternative scenario. The value of the generation, in each of the base case and the alternative scenarios, is calculated as the sum for all hours of the year of the estimated hourly market clearing price times the hourly Ontario generation (plus net imports) used to meet Ontario Primary Demand.
- The energy that replaces the lost nuclear production is a combination of increased coal-fired and gas-fired generation in Ontario plus higher imports and lower exports.
- The results are summarized in the table below.

Prepared April 1, 2008		BP2008	Nuc -25%	Nuc -50%	Delta -25	Delta -50	BP2009	Nuc -25%	Nuc -50%	Delta -25	Delta -50
		2008					2009				
Demand											
Ontario Primary Demand	GWh	150,778	150,778	150,778	-	-	151,032	151,032	151,032	-	-
Interconnected Market Demand	GWh	15,734	10,362	5,332	(5,372)	(10,402)	17,732	12,133	6,900	(5,599)	(10,832)
Total Demand	**GWh**	**166,512**	**161,140**	**156,110**	**(5,372)**	**(10,402)**	**168,764**	**163,165**	**157,932**	**(5,599)**	**(10,832)**
Supply											
Non-OPG											
Imports into Ontario	GWh	5,666	8,309	11,220	2,643	5,554	4,218	6,869	9,015	2,651	4,797
Non-OPG (Ontario)	GWh	51,009	51,946	53,342	937	2,332	53,524	54,820	57,462	1,296	3,938
Non-OPG Total	**GWh**	56,675	60,255	64,562	3,580	7,887	57,742	61,689	66,478	3,946	8,735
OPG Total	**GWh**	**109,837**	**100,885**	**91,548**	**(8,952)**	**(18,289)**	**111,021**	**101,477**	**91,454**	**(9,545)**	**(19,567)**
Total Supply	**GWh**	**166,512**	**161,140**	**156,110**	**(5,372)**	**(10,402)**	**168,764**	**163,165**	**157,932**	**(5,599)**	**(10,832)**
OPG Generation											
Non Nuclear Total	GWh	58,389	62,300	65,851	3,911	7,462	61,119	64,045	66,515	2,926	5,396
Nuclear Total	GWh	51,448	38,585	25,697	(12,863)	(25,751)	49,902	37,432	24,939	(12,470)	(24,964)
Total OPG	**GWh**	**109,837**	**100,885**	**91,548**	**(8,952)**	**(18,289)**	**111,021**	**101,477**	**91,454**	**(9,545)**	**(19,567)**
Spot Price Forecast (7x24 C$/MWh)	**C$/MWh**	**40.2**	**45.8**	**55.2**	**5.6**	**15.0**	**40.5**	**44.3**	**48.7**	**3.8**	**8.2**
Incremental Cost to Ontario	**M$/CAD**				**444**	**1,523**				**281**	**784**

Pollution Probe Interrogatory #9

Ref: Ex. C2-T1-S1, page 9

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

With regard to the views of capital market participants included in Ms. McShane's "review" mentioned at page 9:

(a) What returns are investors expecting from their share holdings in the traded utility entities in Canada?

(b) What returns have investors achieved on their share holdings in the traded utility entities in Canada?

(c) How do the returns achieved in part (b) compare to the returns that these investors achieved from holding the market index in Canada?

(d) Please have Ms. McShane[1] provide all of the references consulted in her "review".

[1] For the purpose of Pollution Probe's interrogatories, references to Ms. McShane include both her and Foster Associates, Inc.

Response

(a) As discussed at Ex. C2-T1-S1, pages 38 - 39 of Ms. McShane's testimony, an analysis of Canadian utility returns shows that the achieved returns (arithmetic and geometric basis) indicates no upward or downward trends; the historic utility returns to shareholders have clustered in the 11-12 percent range. This historic range is a reasonable proxy for investor expectations.

(b) Please see Ex. C2-T1-S1, page 38 (Table 3) of Ms. McShane's testimony.

(c) Over the long-term, the returns from the traded utilities have been higher; see Ex. C2-T1-S1, Schedule 4, page 218 and Schedule 11, page 228 of Ms. McShane's testimony.

(d) The following documents are attached:

1. Conference Board of Canada, *Electricity Restructuring: Opening Power Markets*, May 2004

2. December 2004 DBRS report for ATCO Ltd

3. November 2004 DBRS report for AltaLink

4. September 2004 DBRS report for FortisAlberta

5. DBRS, *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

6. S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable,* November 9, 2004

7. S&P, *Research Summary: AltaLink,* June 5, 2006

8. S&P, *Research: Union Gas*, August 24, 2006

9. S&P's *Industry Report Card: Regulatory Rulings, M&D, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006,

10. CIBC World Markets Report entitled *Pipelines and Utilities: Time to Lighten Up"*, December 2001,

11. National Energy Board's *Canadian Hydrocarbon Transportation System* report, 2005

12. National Energy Board's *Canadian Hydrocarbon Transportation System* report, 2006

13. National Energy Board's *Canadian Hydrocarbon Transportation System* report, 2007

14. Karen Taylor, BMO Capital Markets, *Pipelines/Gas & Electric Utilities*, December 7, 2006

Filed: 2008-04-08
EB-2007-0905
L-12-9
Attachment 1

The Conference Board of Canada
Insights You Can Count On

Briefing March 2004

Electricity Restructuring
Opening Power Markets

About the Electricity Restructuring Series
This briefing is the fifth in a series that highlights key learnings from the experience of North American and U.K. electricity restructuring initiatives over the past decade. The briefings focus on the impacts of public policies in the areas of economic regulation, air quality and climate change on investment in electricity generation and transmission, and on trade across regions.

Investment is needed in transmission capacity. Electricity in Canada and the United States has become a North American phenomenon, with growing volumes of exports and imports between the two countries. The result is a highly interconnected, complex continental network—one that is flexible in responding to fluctuations in demand and supply, but is more vulnerable in the event of a major failure.

Yet challenges exist to getting investment. North America's evolving electricity sector must find ways to raise the level of investment in order to strengthen the transmission infrastructure. This briefing suggests possibilities, while outlining why investment is needed and identifying some of the obstacles.

INVESTMENT IS NEEDED

Under-investment in critical infrastructure cannot be sustained. Witness the Aug. 14 blackout. Its cascading nature underscored the need not only for a more resilient electricity infrastructure, but also for a less brittle system overall.

New demands due to trade, combined with an aging system, have created congestion on transmission lines. This congestion has given rise to an untenable situation with respect to reliability, and constitutes a barrier to electricity trade. In fact, the lack of adequate transmission has become a bottleneck to the development of generation in several areas. An inadequate infrastructure not only threatens electricity reliability; it also contributes to volatility in electricity prices and higher prices for consumers in constrained zones.

Transmission lines are strained and overtaxed, largely because investment in continental transmission capacity has stagnated while network congestion has increased. The North American Electric Reliability Council (NERC)

reported in 2002 that the number of power deals that could not be fulfilled due to transmission constraints quintupled, from 300 in 1998 to 1,500 in 2002.[1] This has created local market power problems and has complicated the operation of wholesale power markets. The grid, in its grim condition, requires upgrading that is estimated to be in the order of $50 billion US.

And money isn't the only issue. Arguably, there are imperfections in transmission governance arrangements that further erode the effectiveness of the transmission infrastructure. The transmission system remains fragmented, with too many system operators relying on incompatible scheduling, transmission pricing and emergency management mechanisms.[2]

Making transmission improvements comprises only one element among many in moving towards the objective of meeting future power needs. Nevertheless, facilitating transmission investment is an important objective, since transmission is currently the factor that most limits the supply of electricity in North America.

Given the deficiencies of the current infrastructure, investment is clearly required to accommodate cross-border exchanges and to ensure the reliability and security of electricity.

Improving transmission is vital—but we must do more to meet North America's power needs, including removing obstacles to investment.

However, investors who are considering the transmission sector in North America face increased risks. Why? In a nutshell, the sector lacks sufficient commercial incentives and potential rewards to balance new risks. We need to remove barriers and address disincentives to transmission investment either through regulatory mechanisms or market signals, particularly as markets continue to integrate.

CHALLENGES FOR INVESTMENT

A number of regulatory issues and uncertainties are limiting investment in new transmission capacity.

PLANNING

A lack of integrated and co-ordinated planning for transmission between jurisdictions exists. The focus on regional supply has limited the expansion of the transmission system; in general, the main problem lies in insufficient regional integrated planning. Moreover, the cumbersome procedures for finding sites and obtaining permission for new facilities deter investors. Multiple authorities are responsible for planning and building new facilities, and investors must endure long lead times before obtaining regulatory approval.[3] For example, three years' lead time is the current estimate to attain the necessary approval for transmission line work in the Pacific Northwest Economic Region. The "not in my back yard" factor is a particular challenge for investors in planning for, and obtaining, suitable new corridors.

The electricity sector suffers from a lack of integrated and co-ordinated planning for transmission.

REGULATED RATES

Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies.[4] These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.[5]

FINANCING

Obtaining desired levels of financing is also problematic. Following the Enron bankruptcy and the ensuing loss of market credibility, it has become more difficult for energy companies to get credit for working capital and to finance their investments. And the upshot is that companies have been curtailing or exiting energy trading and marketing, and energy trading activity is down more than 70 per cent in the United States.[6] In turn, there is a lack of financing to pursue projects,[7] which has reduced the incentive to pursue new infrastructure projects or new transmission connection technologies.

REGULATORY UNCERTAINTY

Several regulatory factors combine to create an unfavourable investment climate in the electricity sector:

- Changes in market restructuring policies in both Canada and the United States are ongoing.
- In light of the continuing attempts to create an even playing field in the wholesale power supply market through non-discriminatory access, there is indecision as to how transmission systems should be operated.[8]
- With increased regionalization, it is unclear who will own and operate the grid in the future. Despite regionalization, the authority to improve the grid remains with individual states and provinces. And, as the blackout demonstrated, key industry decision-makers are unsure of their regulatory options during emergencies or market events.[9]

ENCOURAGING INVESTMENT

Encouraging investment increasingly preoccupies the industry as a whole. The Canadian Electricity Association (CEA) has estimated that about $150 billion in investment will be required in the electricity sector over the next 20 years, either to replace aging capacity and infrastructure or to add to what already exists. And the industry will be relying on private capital for much of this future investment.[10]

To secure the substantial sums that will be required by the electricity sector over the next 20 years, several investment challenges must be overcome.

Key players have been pushing politicians for regulatory reform to encourage investment in transmission. For example, the Edison Electric Institute has urged the U.S. Congress to update federal laws that restrict critically needed investment in the power transmission system. The CEA, along with the Canadian Gas Association, is urging multi-jurisdictional efforts to improve the investment climate in Canada.

Ideally, a multifaceted approach should be designed to overcome investment challenges. This section presents five key elements that such an approach should encompass.

RATES OF RETURN AND DEPRECIATION

As the CEA has pointed out, investors must see reasonable rates of return on their capital.[11] Specifically, the CEA contends that rates of return should recognize the value that the transmission grid plays in the economy. Rates should include clear signals on congestion and losses to transmission users, and should encourage technological innovation.

Increases in regulated rates of return on infrastructure projects would provide better incentives for building transmission. Rate improvements could assist in enhancing the security and reliability of the overall electricity system by attracting new investment to reduce congestion, increase import/export capability, add capacity and support competitive markets. A more secure and reliable system would engender greater competition for infrastructure contracts and could lead to lower costs for such work and lower consumer prices.

The CEA has issued a call for substantially higher capital cost allowance (CCA) rates to reflect the economic life of depreciating assets and to permit expansion. “Given steadily growing demand and long lead times to plan and bring new supply and infrastructure on-line, a decision on CCA rates is urgently needed to allow utilities to build out infrastructure equivalent to approximately 35 per cent of existing capacity over the next two decades.”[12]

It is important that Canada’s rates be competitive with those of the United States so that both countries can maintain a solid pace of transmission infrastructure improvement.

Furthermore, the risk profile of new transmission facilities is generally greater than that for existing facilities. These greater risks—and the lack of regulatory recognition of these risks—may make utilities reluctant to pursue investment. Regulators should therefore recognize these additional risks when setting rates.[13]

Maintaining competitive rates is a necessary, but not a sufficient, condition for investment, however. It is important to improve rates in Canada, but, given that U.S. transmission companies are not investing adequately either, there are clearly other issues that must be addressed in order to get the investment that is so evidently needed.

PLANNING

The blackout prompted serious thought about planning, and the merits of regionalization. The U.S. Federal Energy Regulatory Commission (FERC) has argued that the blackout demonstrated the need for regional co-ordination and planning, and for national standards. FERC's regional transmission organization (RTO) system aims to formalize the regional planning process and efficiently manage the growth of the transmission system.[14] Standard Market Design (SMD), an attempt at standardization and regionalization, may boost infrastructure investment. SMD is a federal plan to standardize all U.S. wholesale power markets. The FERC proposal calls for a single set of market rules that would eliminate the differences between regional electricity markets. FERC views these differences as barriers that limit the ability of energy users to get access to lower-cost power resources.[15] The current energy bill delays SMD until 2007.

The Aug. 14 blackout underscored the need for planning, although differences of opinion exist as to how best to proceed.

Some states and provinces have chosen a different interpretation of the blackout, regarding it as an indication that they should isolate themselves on the grid to avoid problems. However some experts, such as Connie Hughes, Chair of the Ad Hoc Committee on Critical Infrastructure for the U.S. National Association of Regulatory Utility Commissioners, argues that there is no reason for breaking down power and energy trade between countries.[16] Although critics of regionalization view it as an infringement on state and provincial rights, integrated planning will likely work more effectively under a regionalized RTO system.

LOCATIONAL MARGINAL PRICING

Locational marginal pricing (LMP) is a market-pricing approach used to manage the efficient use of the transmission system. LMP sets prices specific to location. It aims to manage congestion by pricing electricity higher in locations where congestion exists, thus providing a precise market-based method for pricing electricity that includes the cost of congestion. By doing so, LMP also indicates where investment in new transmission facilities is most needed. LMP has been recognized as a significant improvement on flawed congestion management and uniform pricing systems.[17]

Some electricity markets have adopted or are adopting LMP: Pennsylvania New Jersey Maryland (PJM ISO) implemented LMP in 1998; New York (NY ISO) in 1999; New England (ISO-NE) in 2003.[18] And it appears to be advantageous; transmission investments are now being proposed in congested zones in these three jurisdictions.[19] Furthermore, FERC is promoting LMP as a means of managing electric transmission congestion. It is the proposed pricing model for many of the RTOs.[20]

LMP could help dissolve "load pockets"[21] and allocate scarce transmission resources more efficiently. Specifically, LMP provides better information for investment decisions by:

- identifying congested areas;
- producing transparent prices that assist investment analysis;
- helping to account for the value of upgrades to the system; and
- assisting in comparing the value of "competing" investment options.

LMP also supports efficient regional planning.

Despite the potential advantages of LMP, it is a complex approach that is not without its own challenges. Using pricing to provide incentives for expansion creates an inherent conflict—it lessens the motivation for transmission companies to deal with congestion, as they may be able to collect more revenues when it exists. To address this concern, New York State auctions the rights to recover congestion revenues to entities that do not control the grid.[22]

Realistically, LMP must be regarded as a necessary feature of a successful system, but not as a solution in itself. Ideally, LMP should be a complementary part of a larger suite of mutually reinforcing tools, both market and regulatory, that, acting together, improve the reliability and efficiency of a power system.[23]

MERCHANT TRANSMISSION

Another option to improve transmission capacity is to permit "merchant" transmission lines. These are projects, usually involving direct current lines, financed by private sector interests to export power over long distances and across borders on a fee-for-service basis. AltaLink is advocating merchant transmission lines, as is its American parent, Trans-Elect, Inc. Merchant

transmission lines have the potential to alleviate transmission congestion issues. Moreover, several merchant transmission projects and long-distance transmission line projects have been proposed as means of connecting more "environmentally friendly" forms of power, such as hydro and wind, to their markets.

However, as a new industry, merchant transmission is unproven.[24] Investment in it is therefore more likely to play a significant role in addressing transmission constraints over the longer, rather than the shorter, term.

RELIABILITY STANDARDS

Electricity reliability, which had long rested on the back burner of political priorities, was quickly marched to the forefront this summer. The blackout, was, of course, the catalyst. It exposed the fact that the current system for maintaining reliability—which is based on standards with which utilities voluntarily comply—is no longer effective. The introduction of competition in wholesale electric markets has eroded the incentive for voluntary action. Now, more than ever, the electricity market needs mandatory standards, along with financial consequences for non-compliance.

NERC is developing a single set of reliability standards to replace its existing operating policies and planning standards. The new standards will address planning and operations, and will include compliance measures for each standard.[25] Legislation on this issue is being considered as part of the national energy bill before the U.S. Congress. Among the bill's measures is a plan to make reliability standards mandatory.[26] The bill has been on hold, but the Senate will conduct a second vote in January 2004. FERC Chairman Pat Wood recently announced that while federal legislation setting electric reliability requirements is the best fix for grid problems, FERC can act to boost reliability if Congress fails to pass a bill.[27]

Canada is in favour of the creation of a self-regulating organization tasked with ensuring reliability. With members from both Canada and the United States, this entity would develop, implement and enforce consistent reliability standards for the interconnected North American electricity grid, while respecting the jurisdiction of sovereign regulatory bodies.[28] The former Natural Resources Minister, Herb Dhaliwal, stated that Ottawa would consider bringing in mandatory reliability standards for power grid operators that could discipline those that do not toe the line.[29]

CANADIAN CHOICES IN A NORTH AMERICAN MARKET

The transmission system across Canada is not as strained as in the United States. Therefore, the urgency to improve transmission capacity in Canada is not as strong. However, considerable concern exists over the lack of interprovincial trade. North–south transmission capacity exceeds east–west capacity since infrastructure has developed on the basis of historical market demand.

Exhibit 1
North American Electricity Trade Is Bright

The single most significant energy trading relationship in the world is between Canada and the United States. Cross-border trade in electricity has been growing dramatically largely due to legislation in the United States, which, over the past 25 years, has encouraged the trading of electricity between and within jurisdictions. Over the last few years, it has also been bolstered by the North American Free Trade Agreement. A more integrated North American electricity market has meant increased integration of regional markets through regional transmission organizations (RTOs) and contractual arrangements.

In 1996, the U.S. Federal Energy Regulatory Commission (FERC) mandated open access for non-discriminatory electricity transmission that led to state and provincial reforms, such as the creation of wholesale trading. FERC imposed some reciprocity conditions upon foreign applicants that required them to open their transmission power grid along the lines adopted for the U.S. wholesale market. Then, in 1999, FERC ordered the creation of Regional Transmission Organizations (RTOs) by December 2001 to better co-ordinate planning; this invited Canadian utilities that buy from or sell electricity to the United States to participate.

Canada dominates U.S. electricity imports—in fact, we actually dominate U.S. *energy* imports. And the United States is increasingly relying upon Canadian energy supplies; almost 100 per cent of American electricity imports come from Canada.[1] Notably, for example, imports of power from BC Hydro arguably prevented California from experiencing widespread blackouts during the 2001 power crisis.[2] However, transmission investment has not kept pace with electricity demand or with generation investment over the past 15 years.

North–south transmission capacity continues to exceed east–west, and there are no strong signs of growth in inter-regional trade in North America. Baseline projections from the Energy Modeling Forum in the United States validate this trend.

American-owned companies continue to be active in Canada, especially in the deregulated provinces of Alberta and Ontario. Canadian companies, such as TransEnergie, Fortis, TransAlta and NS Power, are increasingly active in the U.S. market.

Given its integrated nature, a continental electricity sector appears to be here to stay.

1 This is according to Canada's most recent trade statistics (2001). Lawrence Martin, "Elbowing aside Brian's legacy," *The Globe and Mail*, June 4, 2003, p. A17.

2 Michael Den Tandt, "Energy-hogging U.S. can't stay sore at us forever," *The Globe and Mail*, April 3, 2003, p. B2.

3 Prices and Emissions in a Restructured Electricity Market, Energy Modeling Forum, Stanford University, May 2001.

The north–south trading of electricity supplies (particularly exports to the United States from Quebec, Manitoba and British Columbia) has been more prevalent, economical and effective than east–west transmission. While cross-border electricity trade is growing, inter-regional trade is not necessarily increasing. Trade is hindered by the fact that Canadian provinces tend to function as silos, with little interprovincial co-operation and extensive interprovincial barriers.

Strengthening east–west electricity trade could bring many advantages to Canada.

In light of the desire in Canada for better flow of electricity among provinces, it is incumbent upon us to explore the viability of strengthened east–west electricity trade in Canada.[30] Additional transmission infrastructure is needed to allow sources of generation, some of which are distant from major demand centres, to be brought to market. While most provinces are interconnected with their immediate neighbours, possible further development of east–west lines, notably those between Ontario and Manitoba, and Ontario and Quebec, must be further examined. A major study about transmission expansion in Canada is underway.[31] There may be significant costs to expanding east–west transmission in Canada, but there might also be environmental benefits. For example, if an Ontario–Manitoba line could supply some capacity to replace coal-fired generation in Ontario (consistent with Canada's climate change and Ontario's energy policies), then it may make good sense as a policy objective.[32]

Strengthening interprovincial links may assist in securing the long-term provincial supply needs, such as in the case of the Ontario–Manitoba link. Additionally, developing an east–west grid could be considered to be an investment in the future and an exercise in nation building.

Canada's priorities must be addressed within the context of the North American electricity market. The U.S. regulatory framework exerts strong influence over Canadian decisions regarding cross-border commercial activity in electricity. Within each country, measures can be taken to bolster integration, but regulatory policy must be co-ordinated across North America.

In moving forward with competitive electricity markets, there are sound reasons to enhance Canada–U.S. and interprovincial transmission transfer capability. But, in making decisions on how to proceed, Canada needs to carefully evaluate the merits and drawbacks of the U.S.-driven initiatives. If, as FERC proposes, membership in RTOs becomes essential for power trading in North America, then there will be significantly stronger reasons for Canadian membership in them. Canada is already facing decisions about joining RTOs, and it should pay particular attention to analyzing the advantages and disadvantages of joining with states in regional relationships.

Canada should also be aware that any decision to adopt SMD would affect not only the functioning of RTO markets, but also the roles of the independent market operators and system operators. The standardization of markets and the introduction of independent transmission providers would change the nature of the market, along with the players themselves. SMD could provide market safeguards and facilitate continental trade. But Canadian companies must carefully balance the potential competitiveness benefits that they could derive from SMD against the loss of independence that it would bring.

Canadians should also bear in mind that policy and regulation designed for the American situation may have unintended impacts on us and on our bilateral relationship. For instance, both the augmented continental movement of electricity and decisions regarding transmission capacity could have implications for competitiveness.[33] Thus, there is a need for ongoing Canada–U.S. dialogue and for building stronger relations, with the objective of minimizing cross-border discrepancies. Ergo, now might be an opportune time for Canada to examine the extent of its involvement with NERC. Moreover, in setting harmonized market rules, regulators should aim to accommodate jurisdictional realities.

MOVING AHEAD WITH OPEN ELECTRICITY MARKETS

Adequate transmission capacity is vital to an efficient electricity market. To strengthen the North American transmission grid, players in the Canadian electricity

sector—regulators, investors, politicians and policy-makers—must make a number of decisions on key issues. In particular:

- In supporting transmission investment, the Canadian electricity sector must consider how best to prepare for an increasingly regionalized electricity system in North America.
- Utilities, transmission companies and system operators should consider the extent of their involvement and their roles in integrated planning.
- Canadian regulators should decide whether improved rates of return on invested capital and CCA rates would result in desired investment activity.
- Regulators should resolve whether LMP could provide additional incentives for new transmission investment and, at the same time, also support regional planning.
- In light of the pending U.S. energy legislation regarding mandatory reliability standards, governments must decide on the possible benefits of forming a new self-regulating reliability organization for North America.

In moving ahead on these issues, we cannot forget to encourage new technologies. They will increase the capacity and efficiency of existing networks and reduce line losses,[34] and will be vital in making grid capacity improvements sustainable.

Exhibit 2
Current Initiatives

- A report for the Federal-Provincial-Territorial Electricity Transmission Working Group was recently completed. The "Regional Electricity Transmission Grid Study" discusses current transmission constraints and barriers to transmission and generation development.
- The Canadian Electricity Association (CEA) has recently published recommendations for an integrated North American electricity market, specifically aimed at enhancing cross-border electricity trade. Interestingly, these proposals are similar to those put forth by the U.S. Federal Energy Regulatory Commission (FERC). The CEA measures include:
  - increased participation in RTOs (regional integration);
  - increased focus on harmonizing market rules;
  - enhancement of cross-border and interprovincial transmission transfer capability; and
  - co-ordination of critical infrastructure protection.[1]
- Ontario has recently formed the Electricity Conservation and Supply Tax Force.
- The May 2002 U.S. National Transmission Grid Study (NTGS), published by the U.S. Department of Energy, highlights many of the legacy transmission issues in the country and proposes 50 specific recommendations.[1]
- The North American Energy Working Group (NAEWG) report—*North America—Regulation of International Electricity Trade* is an overview of federal regulations in Canada, the United States and Mexico with respect to the authorization of the construction and operation of international power lines, and the authorization of electricity exports and imports.

[1] Canadian Electricity Association, *Canadian electricity and the economy—The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance* (Toronto: Canadian Electricity Association, 2003).

Finally, to effectively address the current challenges preventing required investment in transmission infrastructure, a strategic and forward-looking Canadian plan must form part of a focused North American approach.

1 ICF Consulting, *The Cascading Blackout: Why Wasn't the Power Outage Contained?* Issue Paper, Fairfax, VA.

2 Paul L. Joskow, "The Difficult Transition to Competitive Electricity Markets in the U.S." (AEI-Brookings Joint Center for Regulatory Studies, July 2003).

3 Nickle's Energy Analects, July 21, 2003. According to Scott Thon, President and Chief Executive Officer of AltaLink.

4 Ibid.

5 New Concepts for the Transmission Grid [on-line]. Department of the Environment Workshop, August 2001. [cited November 2003] Available from <www.ornl.gov/HTSC/pdf/roadmap080301/dale.pdf>.

6 According to Russell J. Tucker, Edison Electric Institute. Presentation [on-line]—March 18, 2003. [cited December 2003] Available from <www.eia.doe.gov/oiaf/aeo/conf/tucker/tucker.ppt>.

7 Nickle's Energy Analects, July 21, 2003.

8 Opinion-editorial, August 15, 2003: "The Power Grid Needs Mandatory Reliability Standards and Infrastructure Investment." [on-line] Steve Wright, Bonneville Power Administrator. [cited December 2003] Available from <www.bpa.gov/corporate/kc/home/docs/2003/testimony_of_%20steve_wright_june_0604_2003%20.pdf>.

9 U.S. General Accounting Office, *Electricity Restructuring: 2003 Blackout Identifies Crisis and Opportunity for the Electricity Sector*, [on-line] November 2003. [cited December 2003] Available from <www.gao.gov/new.items/d04204.pdf>.

10 Hans Konow, CEA President, Nickle's Energy Analects, Oct. 3, 2003.

11 Canadian Electricity Association, *Canadian electricity and the economy—The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance* (Toronto: Canadian Electricity Association, 2003).

12 Nickle's Energy Analects, Oct. 3, 2003. Hans Konow, CEA President. CEA wants CCA rates to rise from 8 per cent to 20 per cent on new generation assets and from 4 per cent to 12 per cent on transmission and distribution assets.

13 These risks include cost disallowances, cost overages, equipment problems and revenue risk. See Navigant Consulting, *Regional Electricity Transmission Grid Study* (Toronto: Navigant Consulting, 2003), p. 63.

14 Department of Energy National Transmission Grid Study [on line]. [cited January 2004] Available from <www.eh.doe.gov/index.html>.

15 Energy User News, Jan. 31, 2003. [cited December 2003] Available from <www.energyusernews.com/>.

16 "Grid reliability essential: Hughes," *Financial Post*, Sept. 3, 2003.

17 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

18 LMP has also operated in the New Zealand market since 1996, and in some South American countries. LMP is being considered in Australia and Ontario, and is planned in California (CAISO), Texas (ERCOT), Midwest (MISO) and Southeast (SeTRANS).

19 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

20 "LMP and Financial Transmission Rights." Presentation by John D. Chandley, LECG Economics Finance, Nov. 11, 2003.

21 Load pockets are geographical areas in which the demand for electricity can exceed the capacity of local generating facilities and/or in which there is an electricity import limitation as a result of transmission line constraints.

22 Auction revenues are allocated to transmission owners and applied to embedded costs of transmission system (to reduce the transmission service charge paid by loads). From Pietrewicz.

23 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

24 Constraints to the development of merchant transmission include market imperfections, immaturity of the merchant transmission industry, significant market risks, and the free rider problem. See Navigant Consulting, *Regional Electricity Transmission Grid Study* (Toronto: Navigant Consulting, 2003), p. 91.

25 NERC Web site. [cited December 2003] Available from <www.nerc.com/>.

26 Barrie McKenna, "Senators block proposed energy bill," *The Globe and Mail*, Nov. 22, 2003, p. B3.

27 *Restructuring Today* [newsletter@restructuringtoday.com], Dec. 3, 2003.

28 Notes for an Address by the Honourable Herb Dhaliwal, PC, MP, (Former) Minister of Natural Resources Canada to the Canadian Electricity Association Washington Forum, Washington, D.C., March 19, 2002. [cited December 2003] Available from <www.nrcan.gc.ca/media/speeches/2002/200232_e.htm>.

29 Simon Tuck, "U.S. firm faces blackout blame," *The Globe and Mail*, Nov. 19, 2003.

30 Alternative options for improving transmission capacity include improving north–south links or boosting generation capacity in centres that require it.

31 The Regional Electrical Transmission Grid Study in Canada.

32 Given the cost of natural gas, expanding gas-based generation stations may be more expensive than getting hydro (e.g., from Manitoba), even with high transmission charges.

33 In the cases of some U.S. regions undergoing restructuring, a key motivation has been a desire to obtain lower-cost power for consumers. One source has been hydro power from Canada.

34 Transmission line losses—power lost due to wire resistance—are a function of distance transported from generator to demand.

The Electricity Restructuring Series

Canadian governments and industries, particularly the energy sector and its major customers, are concerned with understanding the impacts of policy choices and market trends. The Electricity Restructuring Series aims to provide insights for public policy makers and business leaders. Members of the Conference Board's Energy Policy Centre have provided guidance and direction for research. This briefing is the fifth of six in the series.

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Electricity Restructuring: Opening Power Markets

by *Erin Down, Al Howatson, Gilles Rhéaume* and *Greg Hoover*

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Briefings summarize the key findings of Conference Board research and outline the implications for member organizations.

Credit Rating Report

ATCO Ltd.

Report Date: December 29, 2004
Press Released: December 29, 2004
Previous Report: November 25, 2003

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RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (low)	Stable	Confirmed	Corporate Debt*
Pfd-2 (low)	Stable	Confirmed	Cumulative Redeemable Preferred Shares, Series 3

RATING HISTORY	Current	2003	2002	2001	2000	1999	1998
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	NR	NR	NR
Corporate Debt*	A (low)	A (low)	A (low)	A (low)	NR	NR	NR
Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	NR	NR	NR

*Highest rating applicable to the direct debt obligations of ATCO Ltd.

RATING UPDATE

The financial profile of ATCO Ltd. ("ATCO" or the "Company") remains Stable, reflecting the primarily regulated operations of its Canadian Utilities Limited ("CUL") subsidiary and the diversification benefits provided by ATCO's non-regulated operations.

ATCO's earnings (excluding gains from the sale of the retail energy supply businesses) for the 12 months ended September 30, 2004, were flat relative to the year-ended December 31, 2003. Higher contributions from the Company's ATCO Structures entity were offset by lower earnings from the Company's primary subsidiary, CUL, the result of recent Alberta Energy and Utilities Board decisions ("AEUB Decisions"), as well as lower proceeds from the Company's Power Generation segment. This reflects the benefits of the Company's diversified asset base, which helps provide earnings stability. Substantially higher depreciation expense, resulting from higher capital expenditures at various ATCO subsidiaries, contributed to higher operating cash flows during this period. This led to a slight improvement in the Company's cash flow-to-adjusted net debt coverage ratio.

Over the medium term, ATCO's earnings and operating cash flows are expected to remain relatively stable, with modest growth coming from expansion in the franchise area and increases in the rate base of the regulated operations of CUL. ATCO Structures is also expected to provide additional growth due to development activity in natural resource industries. Annual capital expenditures are forecast to be between $500 million and $600 million over the medium term due to continued investment in capital projects, primarily at the regulated operations of CUL. DBRS expects that ATCO will continue to incur free cash flow deficits. Key cash flow and coverage ratios, however, are expected to remain stable, primarily due to the Company's diversified asset base and the fact that approximately 65% to 70% of its earnings are from regulated businesses. The per cent net debt in the capital structure is anticipated to remain below 55%.

While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

RATING CONSIDERATIONS

Strengths:

- Investment in regulated utilities (approximately 67% of net earnings) provides stability to dividend payments
- Diversified asset base – by business type and geography
- Very low leverage for a holding company structure
- Strong franchise area, favourable market conditions

Challenges:

- Low regulated rates of return/deemed equity; regulatory risk/lag
- Earnings sensitivity to weather and to interest rates as related to ROEs
- Growing non-regulated portfolio increases business risk profile

FINANCIAL INFORMATION

	12 mos. ended	For the year ended December 31				
Consolidated Basis	Sept. 2004	2003	2002	2001	2000	1999
Fixed-charges coverage (times)	2.24	2.47	2.36	2.43	2.43	2.41
% adjusted net debt in capital structure (1)	49.5%	51.3%	53.6%	56.6%	60.3%	60.3%
Cash flow/adjusted net debt (1)	18.1%	17.3%	16.8%	17.7%	16.5%	16.9%
Cash flow/capital expenditures	0.86	0.97	0.76	0.72	0.99	1.21
Segmented Income						
Canadian Utilities (before extras., net of min. int.)	129.7	134.4	123.3	123.1	118.1	103.8
Extraordinary items	28.5	0.0	34.9	0.0	0.0	0.0
Wholly owned subsidiaries	11.1	5.4	13.4	12.6	11.9	13.6
Holding company financing	(8.6)	(8.6)	(8.6)	(11.3)	(17.3)	(16.7)
Net income ($ millions) (as reported)	160.7	131.2	163.0	124.4	112.7	100.7
Operating cash flow ($ millions)	488.6	477.9	462.1	472.4	448.0	426.6

(1) Net of uncommited cash. Retractable prefs. treated as debt; cum. prefs. and prefs. as part of minority interest given 70% equity treatment.

THE COMPANY

ATCO is a holding company whose primary investment is 51.9% of CUL. CUL is a holding company whose principal subsidiaries include regulated electricity and gas transmission and distribution utilities primarily based in Alberta, as well as electricity generation assets in Alberta that are subject to legislatively mandated long-term power purchase arrangements (PPAs). In addition to non-regulated subsidiaries and holdings in England, Australia, and Canada, ATCO's other investments include wholly owned subsidiaries involved in the manufacture, sale, and lease of transportable shelters throughout the world and in noise management

AUTHORIZED COMMERCIAL PAPER AMOUNT No program in place.

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RATING APPROACH

- Key considerations in assessing the credit ratings for ATCO include the following factors:
  - An analysis of the strength of the companies controlled by ATCO. This includes a 51.9%-ownership of CUL, a 100%-ownership of ATCO Structures, ATCO Noise Management, ATCO Resources, and ATCO Investments;
  - The strength of the balance sheet and cash flows at the holding company level;
  - The benefits of business, product, and geographic diversification; and
  - Structural subordination of the holding company. Structural subordination exists between the operating companies and holding company, as the holding company does not have first claim on the assets of the operating companies.

COMPANY PROFILE

ATCO:

ATCO is a holding company whose primary investment is 51.9% of CUL. ATCO's other investments include wholly owned subsidiaries ATCO Structures, ATCO Noise Management, ATCO Resources, and ATCO Investments. In August 2004, the Company reorganized its structure into three business groups: Utilities (which includes the Company's regulated electric, gas, and water businesses); Power Generation (which includes both the non-regulated generating assets and the generating assets that operate under legislatively mandated long-term PPAs; and Global Enterprises (which includes other non-regulated business operations of the Company).

CUL:

CUL (rated "A"/R-1 (low) – see separate report dated December 23, 2004) is a holding company whose principal operating subsidiaries are involved in regulated gas, electricity, and water utility businesses and related non-regulated businesses. CUL's regulated businesses currently comprise about 67% of ATCO's net earnings, providing an important degree of stability to its financial position.

CUL's primary operating businesses consist of the following:

CU Inc. [rated A (high)/R-1 (low)] – see separate report dated November 26, 2004) is a holding company with regulated gas (ATCO Gas and ATCO Pipelines) and electricity (ATCO Electric) utility operations, regulated transmission and distribution of water (CU Water), as well as electricity generation assets that now operate under legislatively mandated long-term PPAs [Alberta Power (2000)]. The PPAs provide relative earnings and cash flow stability, similar to the other regulated businesses, as long as the plants can produce their committed outputs of electricity. ATCO Electric's business franchise covers most of northern Alberta (north of Edmonton and parts of central Alberta), as well as regions in the Yukon and the Northwest Territories. ATCO Gas' franchise covers most of Alberta.

ATCO Power Ltd. is involved in the development, construction, operation, and management of independent power projects (IPPs) in Canada (Alberta, B.C., Saskatchewan, and Ontario), the U.K., and Australia. ATCO Power and ATCO Resources (a direct subsidiary of ATCO) own an important portion of these generation assets – 1,539 MW out of the total capacity of 3,302 MW that is currently operational.

ATCO Midstream is involved in gas gathering, processing, storage, and supply management.

ATCO Frontec is involved in project management and technical services for the defence, telecommunications, transportation, and industrial sectors.

Other businesses (non-regulated) consist of the following: (1) information systems and technologies, and customer care services for gas and electricity utilities and marketers (ATCO I-Tek); (2) the sale of fly ash and other combustion by-products produced from coal-based generation (ASHCOR) and a 50% interest in a wood preservation products manufacturer (Genics Inc.); and (3) travel services (ATCO Travel).

Other ATCO Subsidiaries:

ATCO's other investments consist of the wholly owned subsidiaries ATCO Structures, ATCO Noise Management, ATCO Resources, and ATCO Investments. On a combined basis, they generally contribute between 10%-15% of ATCO's net recurring earnings.

ATCO Structures is engaged in the manufacture, sale, and lease of transportable shelters and related products throughout the world.

ATCO Noise Management provides turnkey solutions for industrial noise, including acoustic enclosures, buildings, barriers, ventilation systems, combustion air intake and exhaust silencers, and other noise abatement components.

ATCO Resources invests directly in independent power projects with ATCO Power, while ATCO Investments currently has investments in real estate in Calgary.

Please refer to Description of Operations – Business Segments for further details on the various business segments.

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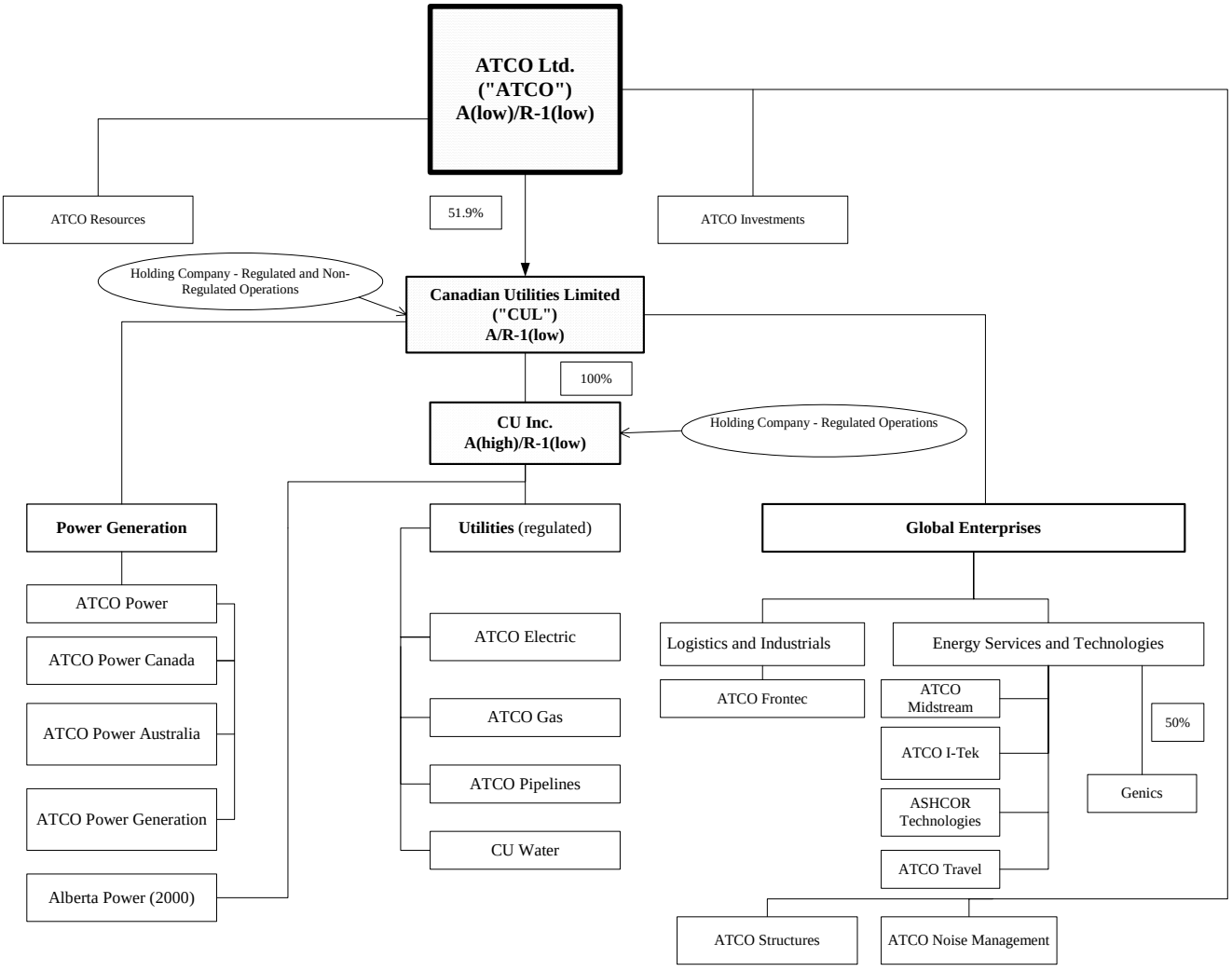
Attachment 2

CORPORATE STRUCTURE



RATING CONSIDERATIONS – please refer to description of operations for discussions of strengths and weaknesses of regulated and non-regulated operations.

EARNINGS AND OUTLOOK

Consolidated basis	12 mos. ended	For the year ended December 31				
($ millions)	Sept. 2004	2003	2002	2001	2000	1999
Revenues	3,616.1	3,929.7	3,196.3	3,767.8	3,077.4	2,376.5
EBITDA	916.9	905.1	842.9	858.2	866.9	810.4
EBIT	615.4	620.4	585.8	600.5	613.2	569.3
Gross interest expense	218.6	217.8	214.2	212.4	206.6	187.3
Net interest expense	176.2	162.8	162.6	157.3	163.4	153.3
Net income (before extras., min. int. & pfd. div.)	297.2	297.8	269.3	268.4	256.7	235.2
Net income (before extras., after pfd. div.)	132.2	131.2	128.1	124.4	112.7	100.7
Net income (as reported)	160.7	131.2	163.0	124.4	112.7	100.7
Return on avg. equity (before extras.)	11.3%	12.1%	13.1%	14.3%	14.4%	14.1%

	12 mos. ended					
Segmented Earnings	Sept. 2004	2003	2002	2001	2000	1999
CUL (net of minority interest)	129.7	134.4	123.3	123.1	118.1	103.8
Wholly owned subsidiaries	11.1	5.4	13.4	12.6	11.9	13.6
Holding company financing	(8.6)	(8.6)	(8.6)	(11.3)	(17.3)	(16.7)
Extraordinary items^	28.5	0.0	34.9	0.0	0.0	0.0
Net income (as reported)	160.7	131.2	163.0	124.4	112.7	100.7

^ For 12 mos ended September 2004, includes the retail energy assets sale to DEML.

Summary:

- For the 12 months ended September 30, 2004, EBIT fell slightly; however, net income remained relatively flat compared to the year ended December 31, 2003.
- The primary reason for the decline in EBIT was the impact of the AEUB Decisions on the regulated operations of CUL, which established overall lower deemed equity ratios and ROEs [not including Alberta Power (2000)] for the Company's utility operations.
  - Offsetting some of the decline in EBIT was increased business activity at ATCO Structures, ATCO I-Tek, and ATCO Midstream.

Outlook:

- Earnings at ATCO are expected to continue to grow at a modest pace, with the bulk of the growth coming from CUL.
  - CUL's regulated utility operations will continue to experience economic expansion in the franchise area, as well as growth in the rate base from higher capital expenditures.
  - Contributions on a full-year basis from the Brighton Beach generating facility will also provide a boost in the short term.
- Continuing business activity in the Company's non-regulated operations will also contribute to earnings growth.
- Over the medium term, earnings could be stressed somewhat by the following factors:
  - Continuing regulatory risk and lag in Alberta, which should be reduced somewhat by the July 2004 Generic Cost of Capital decisions. To date, however, there has been little improvement in the timeliness of regulatory hearings and decisions;
  - The oversupply of generation in Alberta, where the bulk of the Company's merchant portfolio is located; and
  - The Company's non-regulated operations, while generally complementary and related in nature, tend to be more volatile than ATCO's stable regulated operations, given the cyclicality of the business environment.
- Overall, ATCO should continue to experience generally stable earnings and some modest earnings growth. The Company is structured around a stable core of regulated utility operations that enjoy earnings growth through economic expansion in their franchise areas and through rate base capital expenditures to meet demand. Complementing this stability are the Company's non-regulated, diversified operations, which will be a key source of earnings growth over the medium term.

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FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	12 mos. ended	For the year ended Dec. 31		Sensitivity Analysis		
Cash Flow Statement (consolidated)	Sept. 2004	2003	2002	Year 1	Year 2	Year 3
EBITDA (before minority interest)	916.9	905.1	842.9	825.2	825.2	825.2
Net income (after min. int., prefs., before extras.)	132.2	131.2	128.1	77.3	69.9	63.0
Depreciation	301.5	284.7	257.1	292.0	306.2	319.6
Other non-cash adjustments (largely min. interests)	54.9	62.0	76.9	70.0	70.0	70.0
Operating Cash Flow	488.6	477.9	462.1	439.4	446.1	452.6
Common dividends	(40.8)	(38.1)	(34.6)	(23.2)	(21.0)	(18.9)
Capital expenditures (net of contrib.)	(568.4)	(491.5)	(608.1)	(550.0)	(550.0)	(550.0)
Gross Free Cash Flow	(120.6)	(51.7)	(180.6)	(133.8)	(124.9)	(116.3)
Working capital changes	36.3	(58.2)	(170.0)	-	-	-
Free Cash Flow	(84.3)	(109.9)	(350.6)	(133.8)	(124.9)	(116.3)
Other investments/acq./sales	50.7	16.4	116.1	0.0	0.0	0.0
Net debt financing	84.7	(89.1)	215.6	133.8	124.9	116.3
Net pfd. equity financing	-	150.0	150.0	-	-	-
Net common equity financing	(6.2)	(4.8)	4.9	-	-	-
Net other financing	1.3	(52.9)	57.2	-	-	-
Net change in cash	46.2	(90.3)	193.2	(0.0)	0.0	(0.0)
Total adjusted net debt (1)	2,698.1	2,763.5	2,742.8	2,831.9	2,956.7	3,073.1
% adj. net debt in capital structure (1)	49.5%	51.3%	53.6%	49.8%	50.0%	50.3%
Fixed-charges coverage (times)	2.24	2.47	2.36	2.21	2.19	2.06
Cash flow/total adjusted net debt (1)	18.1%	17.3%	16.8%	15.5%	13.9%	14.0%

(1) Net of uncommitted cash holdings.

Retractable preferred shares treated as debt, cumulative preferreds, and preferreds as part of minority interest given 70% equity treatment.

Summary:

Consolidated Basis

- For the 12 months ended September 30, 2004, operating cash flows continued to increase as a result of higher depreciation expense associated with higher capital expenditures in recent years.
- Higher capital expenditures, related to regulated electric transmission projects, as well as workforce housing assets at ATCO Structures, contributed to a significant gross free cash flow deficit for the year ended December 2003.
  - This deficit was offset by positive working capital changes resulting from the sale of the retail energy supply businesses to Direct Energy Marketing Limited ("DEML").
- ATCO's key financial ratios and balance sheet continue to remain strong, reflecting the core stability of the regulated operations, diversification benefits of the non-regulated businesses, and prudent management of the organization as a whole.

On a non-consolidated basis

- ATCO continued to generate operating cash flows well in excess of its capital expenditures and common dividend payments during 2003.
  - ATCO continues to have no debt outstanding and only $150 million in preferred shares.
  - Dividends received from its subsidiary companies continue to be more than sufficient to cover its preferred shared dividends.

Outlook:

Consolidated Basis

- Over the medium term, operating cash flows should continue to increase, reflecting modest growth in the Company's regulated operations' rate base and franchise area.
- Annual capital expenditures are projected to be between $500 million and $600 million over the next four years, primarily due to a number of capital projects at CU Inc.
  - Operating cash flows are not expected to be sufficient to internally fund capital expenditures and dividend payments.
  - The Company will continue to fund these deficits as they have in the past, with debt and common and/or preferred equity.
- Working capital requirements have declined significantly since the sale the Company's retail energy supply businesses to DEML, thus reducing its liquidity needs substantially.
- Key cash flow and coverage ratios are expected to remain relatively stable given the high proportion of regulated activities, which provide stability to ATCO's operating cash flows. As the proportion of non-regulated activities continues to grow, gradual improvement in key ratios will be expected in order to maintain the ratings.

On a non-consolidated basis

- ATCO's per cent adjusted debt in the capital structure is expected to remain low and the Company is expected to continue to generate free cash flow surpluses.
- ATCO is not expected to access the public debt markets in the near term.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used are based neither upon any specific information provided by the Company, nor any expectations that DBRS has concerning the future performance of the Company.

Assumptions:

- EBITDA declines by 10% in Year 1 and remains flat thereafter.
- Annual capital expenditures are $550 million.
- Annual dividend payments are 30% of net income.
- Free cash flow deficits are 100% debt-financed.

Outcomes:

- ATCO's percentage net debt in the capital structure would continue to remain in line with the acceptable range for the rating (below 55%).
- ATCO would record a cumulative free cash flow deficit of approximately $375 million and see its debt level rise by approximately the same amount, resulting in a modest deterioration in its key coverage ratios.
  - Key coverage and cash flow ratios would still remain relatively strong for the current ratings.

LONG-TERM DEBT MATURITIES AND BANK LINES

Debt Maturity Schedule (as at September 30, 2004)

($ millions)	2004	2005	2006	2007	2008
Recourse	136.9	136.1	187.7	79.0	100.0
Non-recourse	53.0	55.7	76.8	61.3	91.6

Summary:

- At September 30, 2004, the Company had credit lines of $1,317.7 million (of which $679.7 million is specifically for CUL and $329.1 million is specifically for CU Inc.) made up of:
  - $588.1 million is available on a long-term committed basis, of which $326.0 million is specifically for CUL;
  - $613.7 million is available on a short-term committed basis, made up of $331.7 million for CUL and $300 million specifically for CU Inc.; and
  - $115.9 million on an uncommitted basis, of which $40 million is for CUL and $29.1 million is for CU Inc.
  - During Q3 2004, the Company reduced its credit lines by a total of $143 million, primarily due to reduced credit needs at CU Inc. following the sale of the retail energy supply businesses to DEML.
- As at September 30, 2004, the total amount outstanding under the above-mentioned credit facilities was $136.7 million.
- ATCO does not currently have a commercial paper program in place.
  - CUL has a Cdn$200 million commercial paper program, which is fully backed by committed bank lines.
  - CU Inc. has a Cdn$300 million commercial paper program, which is fully backed by committed bank lines.
- In addition, ATCO's consolidated maturity schedule is relatively well spread out, minimizing refinancing risk.

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DESCRIPTION OF OPERATIONS

Canadian Utilities Limited (51.9% interest) – accounts for the majority of earnings at ATCO.

Segmented Earnings	12 months ended	For the year ended December 31				
($ millions)	Sept. 2004	2003	2002	2001	2000	1999
Regulated (1)	167.0	174.4	157.2	150.3	153.1	156.0
Non-regulated	83.3	84.9	80.5	86.8	74.3	44.1
Extraordinary/non-recurring items	55.1	0	67.3	0.0	0.0	0.0
Consolidated net income (as reported)	305.4	259.3	305.0	237.1	227.4	200.1
Net income accruing to ATCO (after min. interest)	158.2	134.4	158.2	123.1	118.1	103.8
Electricity distribution throughputs (GWh)	9,882	9,768	10,224	10,108	10,392	10,068
Gas distribution throughputs (bcf)	203.1	207.7	209.4	188.6	205.0	185.4
Electricity generated from PPA plants (GWh)	8,072	8,814	8,597	9,442	8,724	8,542
IPP electricity generated (GWh)	6,894	5,664	4,402	4,401	3,661	3,697

(1) Includes generation assets under PPAs.

REGULATED

Utilities Segment – includes ATCO Electric, ATCO Gas, and ATCO Pipelines

Strengths:

- Regulated businesses provide a degree of financial stability.
- Track record of generating strong operating cash flows.
- Diversified energy portfolio.
- Strong franchise area.

Challenges:

- Regulatory risk/lag.
- Low regulated rates of return/equity base.
- Earnings sensitive to weather and to interest rates as related to ROE.

Summary:

- The AEUB regulates ATCO Electric, ATCO Gas, and ATCO Pipelines.
- In December 2002, DEML agreed to purchase the retail energy supply businesses of ATCO Electric and ATCO Gas and, on May 4, 2004, the transaction was completed and closed.
  - Proceeds of the transfer were $90 million, of which $45 million was paid at closing, with the remainder to be paid 12 months following closing.
  - As a result of this transaction, ATCO Electric and ATCO Gas are no longer responsible for supplying customers with the commodity; they will, however, continue to provide the regulated transportation and distribution services.
- In addition, effective May 4, 2004, is a ten-year contract that DEML signed with another subsidiary of CUL, ATCO I-Tek Business Services, for billing and call centre services to ensure continued quality customer service.

Electricity

- ATCO Electric (distribution and transmission) is regulated using a cost-of-service methodology.
- From 1997-2002, ATCO Electric's approved annual revenue requirement for Alberta-based operations (including that for 2002) had been achieved through a negotiated settlement.
- For 2003 rates, the AEUB established an ROE of 9.4% for both of ATCO Electric's Transmission and Distribution operations in October 2003, on allowed equity ratios of 32% and 35%, respectively.
- For 2004 rates, as a result of the Generic Cost of Capital Decision (GCC), the ROE was revised upwards to 9.60% and common equity ratios for ATCO Electric's Transmission and Distribution business were set at 33% and 37%, respectively.
- On November 30, 2004, and as a result of the application of the adjustment formula (please see Generic Cost of Capital section below), the 2005 ROE was adjusted downwards to 9.50% if ATCO Electric should file a rate application during 2005; otherwise, it will remain at 9.60%.

Gas Transmission & Distribution

- Effective January 1, 2001, CU Inc. merged and restructured its two gas subsidiaries (formerly Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited) into ATCO Gas and ATCO Pipelines Ltd.
- However, for regulatory purposes, separate accounts must be maintained for four divisions (ATCO Gas North, ATCO Pipelines North, ATCO Gas South, and ATCO Pipelines South).
- ATCO Gas (gas distribution) and ATCO Pipelines (gas transmission) are both regulated by the AEUB under a cost-of-service methodology.
- In August 2002, ATCO Gas filed a general rate application for the 2003 and 2004 test years.
  - In the application, ATCO Gas filed combined revenue requirements for ATCO Gas North and ATCO Gas South.
  - In its decision issued October 1, 2003, the AEUB directed CU Inc. to maintain separate revenue requirements for the two divisions and also approved an ROE of 9.50% on equity of 37% for 2003 and 2004, with the GCC decision applying in 2005.

- For 2005 rates, the GCC established a common equity ratio of 38%, with the ROE set at 9.50% if ATCO Gas should file a rate application during 2005; otherwise the ROE will stay at 9.60%.
- ATCO Pipelines filed a rate application in February 2003 for the test years 2003 and 2004.
  - In December 2003, the AEUB established an ROE of 9.5% for 2003, on a common equity ratio of 43.5%.
  - For 2004 rates, the GCC established an ROE of 9.60% and a common equity ratio of 43%.
- The 2005 ROE was set at 9.50% if ATCO Pipelines should file a rate application during 2005; otherwise the ROE will stay at 9.60%.

Generic Cost of Capital

- In late 2002, the AEUB decided to call a GCC hearing to consider matters for utilities under its jurisdiction, including the regulated operations of the Company, ATCO Electric, ATCO Gas, and ATCO Pipelines.
  - The AEUB rendered its decision on July 2, 2004, establishing a common ROE for all utilities in Alberta of 9.60% for 2004 (and reflected in the 12 months to September 30, 2004, financial results), adjusted annually, beginning in 2005, based on 75% of the change in the long-Canada bond yield. The AEUB also established common equity ratios for the Company's regulated operations.
- The outcome of the GCC decision, as it affects the Company, is moderately favourable compared with the previous regulatory decision.
  - Furthermore, the standardization of cost of capital matters should reduce regulatory lag in the future, although to-date, there has been little improvement in the timeliness of regulatory hearings and decisions.
  - The 2004 GCC ruling generally provided some uplift to the ROEs and common equity ratios previously established via the 2003/2004 rate decisions. However, the recent formulaic adjustment resulted in a decline in the 2005 ROE to 9.50% from 9.60%, only for those utilities that file a rate application in 2005.

POWER GENERATION SEGMENT - REGULATED

Alberta Power (2000)

Strengths:

- Legislatively mandated PPAs allow for recovery of forecast costs (variable and fixed), incorporate 450 basis points risk premium above forecast ten-year Government of Canada bonds, and have a deemed equity component at 45%.

Challenges:

PPAs increase business risk relative to the previous framework due to the obligation to meet specified output commitments.

Generation Assets under PPAs – Alberta Power (2000)

	Fuel source	Net capacity MW
Battle River (3 units)	Coal	679
Sheerness (2 units)	Coal	375
Rainbow (2 units)	Gas	90
Sturgeon	Gas	18
Total		1,162

Summary:

- The PPAs incorporate annually adjusted, formula-based ROEs, consisting of a fixed 450 basis point risk premium above forecast ten-year Government of Canada bond yields, with minimum ROEs set for certain plants near the end of their useful lives to ensure that operating risks are adequately compensated for.
  - Deemed equity for the generation assets under the PPAs has been set at 45%.
  - The ROE for both 2003 and 2004 was set at 9.99% and 9.79%, respectively, down from 10.18% in 2002.
  - The PPAs also incorporate incentives that encourage operating efficiencies.
  - All benefits and risks associated with meeting efficiency targets are borne by the generator.
- The increased business risks facing ATCO under the PPAs are as follows.
  - ATCO is obligated to meet specified output commitments. Generators will be penalized (required to make a payment to the PPA holder) if actual output is below the specified capability of the respective unit. However, if generators exceed these thresholds, they are entitled to an incentive payment.

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- Forecast capital expenditures over the term of the PPAs may be below actual requirements. The variance is not recoverable from the PPA holder.

- Establishing who is at fault and defining "force majeure" in the event of an unplanned shutdown may be difficult, leading to disputes and litigation. ATCO's subsidiary, CU Inc., was faced with such a situation in 2003 when output was curtailed at the Battle River Generating Plant due to low water levels in the cooling pond. CU Inc. made a force majeure claim, which was successfully resolved in September 2004, when they were awarded $10.4 million by an arbitration tribunal. This payment essentially refunded the incentive payments that CU Inc. had previously made to the PPA holder for the curtailed production.

NON-REGULATED

Power Generation and Global Enterprises – Includes ATCO Power, ATCO Midstream, ATCO Frontec, and ATCO I-Tek

Strengths:

- Non-regulated assets offer greater earnings growth potential and higher rates of return than the typically lower regulated rates of return of CUL's regulated business segments.
- Long-term sales contracts with fuel cost flow-through minimize merchant power risks.
- Diversified asset base, both geographically and by asset type.

Challenges:

- Non-regulated generation assets are more highly leveraged than regulated assets and subject to increased competitive pressures.
- Additional business risks (currency, counterparty) increase overall risk profile.
- Merchant power risk.
- Potential construction cost overruns.

POWER GENERATION SEGMENT

Independent Operating Power Projects	Total capacity (MW)	ATCO's share (MW)
McMahon, B.C.	120	60
Primrose, Alberta	85	43*
Poplar Hill, Alberta	43	43*
Rainbow Lake, Alberta	89	45*
Joffre, Alberta	480	192*
Valleyview, Alberta	46	46*
Oldman River, Alberta	32	32*
Muskeg River, Alberta	170	119*
Cory, Saskatchewan	260	130*
Barking, U.K.	1,000	255
Heathrow Airport, U.K.	14	7
Osborne, Australia	180	90
Bulwer Island, Australia	33	17
Scotford, Alberta	170	170*
Brighton Beach, Ontario	580	290*
Total	3,302	1,539

* 20% of CUL's share belongs to ATCO Resources Inc., a direct subsidiary of ATCO Ltd.

Summary:

- Contributions from this segment accounted for approximately 13.8% of ATCO's total earnings (excluding the $28.5 million gain from the sale of the Company's retail energy supply businesses to DEML and after preferred dividends) for the 12 months ended September 30, 2004, which was roughly in line with 14.4% of total earnings at year-end 2003.
  - For the 12 months ended September 30, 2004, the Company brought on-line an additional 782 MW of generating capacity (492 MW net to ATCO).
  - The Company has an effective ownership of 1,539 MW of non-regulated power projects and the newest power facility, the Brighton Beach power plant, was brought on-stream in July 2004. The plant is operated under a tolling arrangement with Coral Energy Canada providing the natural gas for the plant and off-taking the electricity produced.
- Independent power projects are currently more highly leveraged than generation assets under the PPAs and the regulated utility businesses.
- However, most of the projects to date have been financed on a non-recourse basis, with ATCO's exposure limited to the Company's equity investment.
- This business unit's risks are currency, counterparty, and merchant power.
  - However, some of the risk is mitigated by ATCO's strategy of having the majority of its power generation subject to long-term sales contracts, including fuel supply contracts.
  - Furthermore, this portfolio is relatively small compared to ATCO's total asset base and is well diversified, minimizing the impact of these risk factors on the Company as a whole.
  - The Company has no new construction projects under way and is focusing on maximizing the operating efficiency of its current portfolio of assets.
  - In September 2004, the Company and SaskPower announced their joint venture to develop a 150 MW wind farm in Saskatchewan would not proceed.
- Risks with the IPPs are related primarily to the Company's merchant power exposure in Alberta given the high gas price environment and the fact that most of its merchant power is gas-fired.
  - While there is a relatively high correlation between electricity prices and gas prices in Alberta, there remain risks due to the oversupply situation in Alberta.

- In addition, the Company has been negatively impacted by the bankruptcy of TXU Europe, one of the counterparties for the power supplied by the Barking plant in the U.K.
  - TXU Europe had a long-term off-take agreement for 27.5% of the power generated by Barking (or 275 MW); ATCO has a 13.2% equity interest in this plant.
  - To date, CUL has received no payments from TXU Europe and there is not yet a replacement off-taker in place.
  - The 275 MW of power is being sold into the U.K. market on a merchant basis under a one-year marketing agreement.

GLOBAL ENTERPRISES SEGMENT

Summary:

- Overall, ATCO Frontec, ATCO Midstream, ATCO Structures, and, to a lesser-but-growing extent, ATCO I-Tek, continue to drive this segment, focusing on core capabilities such as camp support services, facilities operation, and gas gathering and processing, information technology solutions and workforce shelter/space rentals products.
- While the ATCO Frontec Balkan's contract expired in September 2003, they secured a new three-year project, with two additional option years, to provide advanced information systems technological support to the NATO Stabilization Force Organization.
  - ATCO Frontec will continue to expand on its expertise in camp support services primarily in the mining industry (such as Voisey's Bay), expand its presence in the Balkans with NATO, and pursue further opportunities with the Canadian Department of National Defence, the U.S. Department of Defence, and the U.S. Air Force.

ATCO Midstream has ownership in fifteen natural gas processing and compression facilities, with a gross licensed capacity of 2,060 million cubic feet per day.

- They also own and operate approximately 1,000 kilometres of raw natural gas pipeline and provide services in gas gathering and processing, natural gas liquids extraction, and energy services.
- ATCO Midstream continues to provide strong contributions to the Global Enterprises segment.
- Future earnings growth over the medium term will likely be realized in new geographic areas such as the far north, east, and west coasts, as well as through contributions from emerging industries such as heavy oil and natural gas from coal.

- ATCO I-Tek continues to provide customer care and billing services, as well as information and technology solutions, in Canada.
  - They were awarded the ten-year contract to provide the DEML billing and call centre services to ensure continued quality customer service
  - They also worked to set up ATCO Gas and ATCO Electric's distribution-only services as a result of the sale of the retail energy supply businesses to DEML.

WHOLLY OWNED NON-REGULATED ATCO SUBSIDIARIES

ATCO Structures, ATCO Noise Management, ATCO Resources, and ATCO Investments

- ATCO Structures' primary businesses include:
  - Providing workforce housing at remote industrial and natural resource development projects. The associated products offered by ATCO Structures include support services, transportation, site preparation, maintenance, and installation of the housing;
  - Providing space rentals (through sale or lease) of relocatable modular offices, classrooms, and other community structures; and
  - The manufacturing of a broad range of relocatable modular products for sale and for its lease fleet.
- For the 12 months ended September 30, 2004, ATCO Structures experienced increased business activity at all of its global operations.
  - In September 2004, ATCO Structures announced that it had been awarded a contract to supply a 2,100 person camp, as well as maintenance personnel, for Nexen Inc., for the Long Lake project in the Athabasca oil sands region of northern Alberta. The scheduled completion date of the project is June 2005, and the project life-span is two years.
- ATCO Noise Management's clients are predominantly from the energy and gas manufacturing sector.
  - The Company is currently concentrating on growing its worldwide operations.
- These wholly owned subsidiaries generally account for about 10%-15% of ATCO's net earnings, significantly higher than during the past couple of years.
  - DBRS expects ATCO to continue managing these operations selectively, such that they will not comprise a significant portion of ATCO's consolidated earnings but rather provide incremental benefits.

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ATCO Ltd.

Balance Sheet (Consolidated)

($ millions)	As at	As at December 31			As at	As at December 31	
Assets	Sept. 2004	2003	2002	**Liabilities & Equity**	Sept. 2004	2003	2002
Cash & equivalents	628.0	391.9	488.8	Short-term debt	108.5	5.6	12.2
Accounts receivable	389.5	596.6	519.4	A/P & accr'ds	380.5	540.9	564.9
Inventories	180.8	184.2	129.3	Other	0.0	0.0	0.0
Deferred gas & electricity costs	0.0	27.2	51.9	L.t.d. due one year	189.9	167.2	135.9
Prepaids	35.8	27.7	27.3	**Current Liabilities**	678.9	713.7	713.0
Current Assets	1,234.1	1,227.6	1,216.7	Deferred taxes & credits	365.3	367.2	312.7
Net fixed assets	5,316.5	5,155.0	4,949.2	Long-term debt	2,732.9	2,675.9	2,811.0
Deferred charges & other	219.6	235.2	237.4	Red. preferred shares	150.0	150.0	150.0
				Minority interest	1,631.8	1,579.3	1,371.8
Total	6,770.2	6,617.8	6,403.3	Shareholders' equity	1,211.3	1,131.7	1,044.8
				Total	6,770.2	6,617.8	6,403.3

Consolidated Basis

	12 mos. ended	For the year ended December 31					
Ratio Analysis	Sept. 2004	2003	2002	2001	2000	1999	1998
Current ratio	1.82	1.72	1.71	1.21	1.18	1.53	1.19
Acc. depreciation/gross fixed assets	39.6%	39.9%	39.2%	39.3%	40.2%	39.5%	38.1%
Cash flow/net debt (incl. debt equiv.)	19.8%	18.9%	18.1%	18.8%	17.1%	17.6%	15.3%
Cash flow/adjusted net debt (1)	18.1%	17.3%	16.8%	17.7%	16.5%	16.9%	14.8%
Adjusted net debt/EBITDA	2.86	2.95	3.17	2.97	3.03	3.00	3.17
Cash flow/capital expenditures	0.86	0.97	0.76	0.72	0.99	1.21	0.87
(Cash flow-dividends)/capital expenditures	0.79	0.89	0.70	0.67	0.93	1.14	0.82
% net debt in capital structure (incl. debt equiv.) (1)	45.1%	46.9%	49.9%	53.5%	58.0%	58.0%	60.6%
% adj. net debt in capital structure (1)	49.5%	51.3%	53.6%	56.6%	60.3%	60.3%	62.6%
Hybrids/common equity	35.6%	37.9%	33.0%	28.5%	21.6%	22.4%	20.1%
Common dividend payout	25.4%	29.0%	21.2%	24.8%	24.2%	23.7%	22.9%
Coverage Ratios (2)							
EBIT interest coverage (times)	2.93	2.99	2.84	3.02	3.12	3.19	3.23
EBITDA interest coverage (times)	4.31	4.30	4.04	4.23	4.35	4.47	4.43
Fixed-charges coverage (times)	2.24	2.47	2.36	2.43	2.43	2.41	2.00
Earnings Quality/Operating Efficiency							
Operating margin	17.0%	15.8%	18.3%	15.9%	19.9%	24.0%	26.7%
Net margin	4.4%	3.3%	5.1%	3.3%	3.7%	4.2%	4.3%
Return on average equity (bef. extras.)	11.3%	12.1%	13.1%	14.3%	14.4%	14.1%	13.7%

		12 months ended	For the year ended December 31				
Segmented Earnings		Sept. 2004	2003	2002	2001	2000	1999
Utilities (gas + electric distribution)	30%	48.0	50.7	41.7	38.3	40.1	47.9
Power generation (incl. PPA generation)	29%	45.9	48.9	37.6	52.6	58.3	35.3
Global Enterprises	19%	31.2	31.5	33.4	26.7	24.3	21.1
Industrials and other	12%	20.0	13.0	17.3	17.4	8.2	11.8
Corporate/inter-segment elimin.	-8%	(12.9)	(12.9)	(1.9)	(10.6)	(18.2)	(15.4)
Extraordinary items	18%	28.5	0.0	34.9	0.0	0.0	0.0
Net income	100%	160.7	131.2	163.0	124.4	112.7	100.7

(1) Net of uncommited cash holdings. Retractable preferred shares treated as debt, cumulative preferreds, and preferred as part of minority interest given 70% equity treatment. (2) EBIT includes interest income; interest expense excludes allowance for funds used during construction (AFUDC), capitalized interest, and debt amortizations; preferred dividends includes min. interest preferred.

Income Statement (Consolidated)	12 mos. ended	For the year ended December 31				
($ millions)	Sept. 2004	2003	2002	2001R	2000	1999
Revenues	3,616.1	3,929.7	3,196.3	3,767.8	3,077.4	2,376.5
Expenses						
Fuel + purchased power	357.9	455.20	408.7	633.5	359.4	259.3
Cost of gas	1,227.2	1,516.90	988.5	1,314.5	1,002.7	550.6
Operating + maintenance	987.7	929.90	857.7	844.0	748.3	678.0
Property/franchise taxes	126.4	122.60	98.5	117.6	100.1	78.2
Depreciation	301.5	284.70	257.1	257.7	253.7	241.1
Operating costs	3,000.7	3,309.3	2,610.5	3,167.3	2,464.2	1,807.2
Operating profit	615.4	620.4	585.8	600.5	613.2	569.3
Interest expense	218.6	217.80	214.2	212.4	206.6	187.3
Non-cash financial charges	(16.4)	(23.30)	(28.6)	(14.9)	(11.1)	(6.3)
Other (income)/expense	(26.0)	(31.70)	(23.0)	(40.2)	(32.1)	(27.7)
Equity earnings	0.0	0.00	0.0	0.0	0.0	0.0
Net interest expense	176.2	162.8	162.6	157.3	163.4	153.3
Pre-tax income	439.2	457.6	423.2	443.2	449.8	416.0
Income taxes (normalized)	142.0	159.80	153.9	174.8	193.1	180.8
Income bef. extras. + min. int.	297.2	297.8	269.3	268.4	256.7	235.2
Minority interest pfd. div.	35.8	33.10	18.2	17.0	16.8	14.9
Minority interest equity income (normalized)	120.6	124.90	114.4	114.0	109.3	96.3
Net income bef. pfd. div. & extras.	140.8	139.8	136.7	137.4	130.6	124.0
Extraordinary items	28.5	0.00	34.9	0.0	0.0	0.0
Preferred dividends	8.6	8.60	8.6	13.0	17.9	23.3
Net income (as reported)	160.7	131.2	163.0	124.4	112.7	100.7

Credit Rating Report

AltaLink, L.P.

Report Date: November 24. 2004
Press Released: November 22, 2004
Previous Report: October 1, 2003

RATING

Rating	Trend	Rating Action	Debt Rated
A	Stable	Downgraded	Senior Secured Bonds

Geneviève Lavallée, CFA/Nick Dinkha, CFA
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RATING HISTORY	Current	2003	2002	2001	2000	1999	1998
Senior Secured Bonds	A	A (high)	A (high)	NR	NR	NR	NR

RATING UPDATE

The rating on the Senior Secured Bonds of AltaLink, L.P. ("ALP" or the "Company") has been downgraded to "A" and the trend changed to Stable from Negative. The trend on ALP's rating was changed to Negative from Stable in September 2003 as a result of the financial implications of certain parts of the 2002/2003 and 2003/2004 transmission tariff decision. Since the trend change, however, ALP's financial results have been better than anticipated and the Alberta Energy and Utilities Board ("AEUB") has released its generic cost of capital decision, which was moderately favourable for ALP relative to the previous tariff decision. Instead, the downgrade reflects the ongoing uncertainty and significant regulatory lag associated with the AEUB's decisions with respect to both ALP and AltaLink Investments, L.P. ("AILP"), ALP's sole limited partner, which has contributed to lengthy time delays in reaching financial decisions by AILP's sponsors. This type of regulatory environment, combined with the fact that AILP has four non-controlling sponsors (each of which has its own mandate), impacts the sponsors' ability to make financial decisions in a timely manner. This has been demonstrated over the past two years by the significant time delays experienced by the sponsors in reaching decisions with respect to the financing of AILP.

In addition, the regulatory environment has increased the uncertainty with respect to the type of support and financing that AILP will receive from its sponsors. One of AILP's sponsors, the Ontario Teachers' Pension Plan Board ("OTPPB"), has indicated that as a result of the AEUB's decision to disallow the full recovery of deemed income taxes in respect of its ownership interest in AILP, it will not provide further equity injections (to ultimately fund ALP's capital expenditure program) unless and until the income tax issue is resolved. The uncertainty with respect to AILP's future financial profile has become an important rating consideration given ALP's reliance on AILP for equity contributions to maintain a stable financial profile, especially in light of ALP's large capital expenditure program over the medium term.

ALP continues to await the outcome of two key regulatory decisions, one of which was outstanding at the time the rating was placed on a Negative trend, namely the review and variance of the rate decision pertaining to 2002/2003 and 2003/2004 rates, while the other pertains to the tariffs for 2004-2007. The potential outcome of these important regulatory decisions has been factored into the current rating.

Over the medium and longer term, ALP's financial profile should remain relatively stable given its low business risk profile and the fact that all of its operations are regulated. ALP's earnings will grow in line with rate base growth, which is expected to grow at a strong pace due to the significant capital expenditure program. As a result of the significant capital projects, ALP will continue to record free cash flow deficits over the medium term. It is the Company's intention to fund the deficits through a combination of public debt and equity injections by AILP such that ALP's financial profile remains stable.

While regulatory risk remains one of ALP's key risks, the challenges associated with the timeliness of decisions and the uncertainty with respect to the type of financing that AILP will receive in the future were the key reasons for the downgrade.

RATING CONSIDERATIONS

Strengths:

- Involved solely in regulated activities
- No volume risk and limited counterparty risk
- Attractive Alberta-based business franchise
- Well-maintained transmission system with a long remaining average operating life

Challenges:

- Regulatory risk/regulatory lag
- Financially weaker parent/lack of a majority sponsor
- Low regulated rates of return/deemed common equity
- Approved ROE sensitive to interest rates
- Free cash flow deficits in the medium term

FINANCIAL INFORMATION

	12 mos. ended	For the year ended April 30		
	July 31, 2004	2004	2003	2002
Fixed-charges coverage (times)	1.98	1.86	2.04	n/a
% debt in capital structure (1)	61.0%	60.8%	60.7%	60.1%
Cash flow/total debt (1)	14.0%	14.7%	14.8%	n/a
Cash flow/capital expenditures (times)	1.00	0.95	1.09	n/a
Net income (before extras.) ($ millions)	30.3	26.4	30.4	n/a
Operating cash flow ($ millions)	78.3	79.9	77.3	n/a
Return on average common equity	8.8%	7.7%	9.0%	n/a
Approved ROE	9.60%	9.40%	9.40%	n/a
Deemed common equity in capital structure	35%	34%	34%	n/a

(1) Includes subordinated debt.

THE COMPANY AltaLink, L.P. ("ALP") owns and operates regulated transmission assets in Alberta. AltaLink Investments, L.P. ("AILP") is the holding company of AltaLink, L.P. The sponsors of AILP include: Macquarie North America Ltd. (15%), Ontario Teachers' Pension Plan Board (25%), SNC-Lavalin Inc. (50%), and Trans-Elect Inc. (10%). AltaLink Management Ltd. is the general partner of ALP, and SNC-Lavalin, and Trans-Elect are the general partners (50/50) of AltaLink Management Ltd.

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REGULATION

- ALP is regulated by the AEUB.
- ALP is regulated under a cost-of-service/rate-of-return methodology.
  - Operations will continue to be subject to regulatory hearings in the absence of negotiated settlements.
- Key financial components of the AEUB's decision with respect to ALP's transmission tariffs for the years 2002/2003 and 2003/2004 (ALP's past fiscal years ended on April 30) included:
  - Deemed common equity of 32% (34% when adjusted for partial tax disallowance);
  - Approved return on equity (ROE) of 9.40% for both years;
  - Cost of debt approved as follows: actual cost of debt for market debt; 8% for subordinated debt issued to the parent;
  - Deemed income tax recovery not approved for OTPPB's ownership interest; and
  - Approved liability method of taxation for federal taxes approved, but flow-through method for provincial taxes.
- ALP subsequently submitted a review and variance application with respect to certain matters included in the above-mentioned decision.
  - The AEUB has not yet released its decision on this application.
- In July 2004, the AEUB rendered its decision on generic cost of capital matters for utilities under its jurisdiction, including establishing deemed common equity ratios for each utility, as well as a common ROE for 2004.
  - The common ROE for 2004 was set at 9.60%, and will be adjusted annually, beginning in 2005, by 75% of the change in the forecast long Government of Canada bond yield.
  - The deemed common equity ratio for ALP was set at 33% (35% when adjusted for partial tax disallowance).
- The outcome of the generic cost of capital decision, as it impacts ALP, is moderately favourable compared to the previous regulatory decision.
  - Furthermore, the standardization of cost of capital matters should reduce regulatory lag in the future, although to date, there has been little improvement in the timeliness of regulatory hearings and decisions.
- In spring 2004, ALP submitted a general transmission tariff application covering 2004 to 2007.
  - DBRS does not expect the outcome of this decision to have a significant impact on ALP's medium-term financial profile given that the key financial factors (i.e. cost of capital matters) have already been established.
- Both ALP and AILP, ALP's sole limited partner, have experienced uncertainty and significant regulatory lag in respect of AEUB decisions.
  - This is an important challenge facing ALP as it has affected its sponsors' ability to make financial decisions in a timely manner, as well as impacting the type of support and financing that AILP will receive in the future from its sponsors.

RATING CONSIDERATIONS

Strengths: (1) ALP is involved solely in regulated transmission operations in Alberta. This provides a high degree of stability to ALP's earnings and financial profile.
(2) Given the framework within which transmission is governed in Alberta, ALP faces no volume risk (total revenue requirements are negotiated for the year and are not dependent on volumes) and only limited counterparty risk as its only counterparty is the Alberta Electric System Operator, a government-created entity. This provides additional stability to ALP's earnings and financial profile.
(3) ALP has one of the strongest transmission franchise areas in Canada. ALP's franchise area covers virtually the entire Alberta customer base and Alberta continues to have some of the strongest economic fundamentals in Canada, as well as the strongest electricity demand growth. Strong economic growth is expected to continue in Alberta over the medium term. Continued strong electricity demand, as well as growing transmission system constraints, bodes well for the growth potential of ALP's transmission network.
(4) Transmission assets have a relatively long average operating life, and ALP's assets are, on average, less than 20 years old. Independent reports indicate ALP's assets have been well maintained. ALP intends to continue to manage and invest in the existing transmission system to maintain reliability.

Challenges: (1) Regulatory risk is the key challenge facing ALP as its financial profile is heavily dependent on the outcome of regulatory decisions. Furthermore, Alberta-based utilities are often burdened by material time lags associated with the regulatory process, adding to the cost, complexity, and uncertainty inherent in the current system. Regulatory decisions have often been delivered well after the fiscal period in question, resulting in charges against the current year's earnings to reflect prior-period adjustments. The outcome of the generic cost of capital decision whereby the AEUB established the approved ROE formula and the deemed common equity component for regulated utilities in Alberta suggests that regulatory lag should be much lower in the future. However, no improvement has yet been seen in the timeliness of regulatory hearings and decisions.
(2) ALP's sole limited partner, AILP, has a significantly weaker financial profile than ALP. While ALP is a stand-alone company regulated by the AEUB with a low business risk profile, the weaker financial profile of AILP poses some risk in terms of providing ALP with the necessary equity injections to maintain its regulated capital structure. Previously, this had not been a limiting factor on ALP's rating. However, the regulatory environment, combined with the fact that AILP has four non-controlling sponsors (each of which has its own mandate), has impacted the

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sponsors' ability to make financial decisions in a timely manner. Furthermore, the regulatory environment has increased the uncertainty with respect to the type of support and financing that AILP will receive from its sponsors in the future. The increased uncertainty with respect to AILP's future financial profile impacts ALP given ALP's reliance on AILP for equity contributions to maintain a stable financial profile, especially given ALP's large capital requirements over the medium term.

(3) In Alberta, as well as in many other jurisdictions in Canada, the rates of return and deemed common equity components approved by the regulators are significantly below those approved for similar operations in the U.S. This acts as a disincentive for investors to allocate capital to Canadian utilities as they can earn higher rates of return in the U.S. from businesses with similar risk profiles. Furthermore, higher deemed common equity in the capital structure generally provides greater protection for bondholders.

(4) Approved ROEs are linked to interest rates, which have been falling in Canada in recent years. This has had a negative impact on earnings and key financial ratios. Given the outcome of the generic cost of capital decision, ALP's earnings and cash flows will remain sensitive to interest rates through approved ROEs. A continued low interest rate environment will keep key cash flow and coverage ratios weaker than they would be otherwise.

(5) Based on conservative assumptions for net income and the projected large capital expenditure program, ALP will post large free cash flow deficits over the medium term. It is the Company's intention to fund these deficits through a combination of debt issuance and equity injections by its parent, AILP, such that the capital structure is maintained near its current structure.

EARNINGS AND OUTLOOK

	12 mos. ended	For the year ended April 30		
($ millions)	July 31, 2004	2004	2003	2002
Net revenues	161.0	154.0	152.2	n/a
EBITDA	109.0	99.5	109.0	n/a
EBIT	61.5	58.2	59.2	n/a
Gross interest expense	31.0	31.3	29.1	n/a
Net interest expense	31.2	31.8	28.8	n/a
Pre-tax income	30.3	26.4	30.4	n/a
Net income (avail. to common)	30.6	26.5	30.4	n/a
Return on average common equity	8.8%	7.7%	9.0%	n/a

Summary:

- ALP's EBIT and net income have generally been stable since ALP began operations, with the unfavourable regulatory decision pertaining to 2002/2003 and 2003/2004 tariffs largely offsetting the impact of rate base growth.
- The higher earnings for the 12 months ended July 2004 relative to the year ended April 2004 was largely due to the outcome of ALP's first transmission tariff application covering both 2002/2003 and 2003/2004, whereby approved revenue requirements were lower than those received under the interim tariff, with the entire amount being booked in Q1 2003/2004
- The lower approved revenue requirements were due to:
  - Lower approved ROE compared to requested ROE; and
  - The disapproval of deemed income tax recovery for OTPPB ownership interest.

Outlook:

- On a full-year basis, ALP's EBIT and net income are expected to be slightly higher as a result of the generic cost of capital decision, which provided for a 9.60% ROE for 2004 compared to the 9.40% ROE previously approved by the AEUB.
- The significant projected capital expenditure program, with the majority being growth-related, will result in a growing rate base, which provides for a favourable earnings growth profile.
  - Annual earnings growth of about 6% is expected over the medium term.
- Despite the favourable earnings growth profile, key financial ratios are expected to remain relatively unchanged due to the regulatory framework and ALP's intention to manage distributions and equity injections to maintain stable financial ratios, thus providing no increased protection for bondholders.
- It should be noted that ALP is awaiting the outcome of two key regulatory decisions: (1) the review and variance of the rate decision pertaining to 2002/2003 and 2003/2004 rates, and (2) the general rate application covering 2004-2007 rates.
  - While these are important regulatory decisions, DBRS does not expect the outcome of these decisions to materially impact ALP's financial profile. However, OTPPB, one of ALP's sponsors, has indicated that the outcome of the review and variance decision will impact whether or not it will provide equity injections in the future to AILP to fund ALP's capital program.
  - DBRS considers the generic cost of capital decision to be the key determinant of the medium-term financial profile of Alberta-based regulated utilities.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	12 mos. ended July 31, 2004	For year ended Apr. 30 2004	2003	Sensitivity Analysis Year 1	Year 2	Year 3
EBITDA	109.0	99.5	109.0	103.6	103.6	103.6
Net income before extraordinary items	30.3	26.4	30.4	24.1	14.5	4.4
Depreciation	49.2	42.3	51.8	54.4	62.2	72.1
Other non-cash adjustments	(0.9)	11.4	(4.9)	(4.3)	(8.4)	(17.0)
Operating Cash Flow	78.7	80.1	77.3	74.2	68.2	59.6
Capital expenditures	(77.9)	(84.4)	(71.1)	(173.0)	(218.0)	(268.0)
Cash flow before working capital	0.7	(4.3)	6.1	(98.8)	(149.8)	(208.4)
Working capital changes	1.6	4.2	(0.9)	0.0	0.0	0.0
Free cash flow before distributions	2.4	(0.1)	5.3	(98.8)	(149.8)	(208.4)
Distributions to AILP	(15.4)	(12.9)	(29.3)	(7.2)	(4.3)	(1.3)
Free Cash Flow	(13.0)	(13.0)	(24.1)	(106.1)	(154.1)	(209.8)
Other investments	0.7	0.1	(0.8)	0.0	0.0	0.0
Net external debt financing	15.6	22.5	15.1	106.1	154.1	209.8
Net debt financing from AILP	0.0	0.0	0.0	0.0	0.0	0.0
Net equity financing from AILP	0.0	0.0	0.0	0.0	0.0	0.0
Other financing	(2.2)	(7.1)	(2.5)	0.0	0.0	0.0
Net change in cash	1.1	2.5	(12.2)	(0.0)	(0.0)	0.0
Cash flow/capital expenditures (times)	1.00	0.95	1.09	0.43	0.31	0.22
Cash flow/total debt	14.0%	14.7%	14.8%	11.2%	8.3%	5.8%
% debt in the capital structure	61.0%	60.8%	60.7%	64.0%	68.0%	72.6%
Fixed-charges coverage (times)	1.98	1.86	2.04	1.63	1.16	0.73

Summary:

- For the 12 months ended July 31, 2004, ALP's operating cash flow was generally stable despite the negative regulatory decision in 2003 and was sufficient to fully fund its capital expenditures, due to lower capital expenditures.
  - Including distributions to AILP, however, ALP continued to record a free cash flow deficit, which was debt financed.
- Despite entirely debt-financing the free cash flow deficit, ALP's per cent debt in the capital structure remained relatively stable, as did its key cash flow and coverage ratios.

Outlook:

- While operating cash flow is expected to grow strongly over the medium term alongside the projected growth in the rate base, it will remain insufficient to fully fund the significant capital expenditure program over the next five years.
  - The large capital expenditure program is related to the significant transmission system requirements in Alberta to maintain reliability, improve efficiency (reduce line losses), and facilitate a well-functioning and stable electricity market.
- The free cash flow deficits are expected to be funded through a combination of public debt issuance and equity injections from AILP such that ALP's cash flow and interest coverage ratios remain relatively stable.
  - Since inception, it has been ALP's intention to maintain about 40% equity in the capital structure compared to the lower deemed common equity, currently at 35%
- As a result, DBRS expects ALP's financial profile to remain generally unchanged from its current profile.
- One of the key challenges to ALP's key financial ratios over the medium term relates to the regulatory lag associated with recovering the costs of long lead-time capital projects.
  - While this will negatively impact financial ratios over a two- to three-year period, DBRS does not view this as a long-term challenge and risk to the rating.
- A key risk, however, which is reflected in the current rating, is the uncertainty with respect to AILP's future financial profile and its ability to provide equity injections to ALP.
  - While it is the sponsors' intention to provide the necessary equity injections to maintain a stable financial profile, the regulatory environment, combined with the fact that AILP has four non-controlling sponsors (each of which has its own mandate), has impacted the sponsors' ability to make financial decisions in a timely manner.
  - Furthermore, OTPPB has stated it will not provide further equity injections unless and until the income tax issue is resolved.

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Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used are based neither upon any specific information provided by the Company, nor any expectations that DBRS has concerning the future performance of the Company.

Assumptions:

- EBITDA declines by 5% in Year 1 and remains flat thereafter.
- Capital expenditures are $173 million in Year 1, increasing to $218 million and $268 million in Years 2 and 3. These capital expenditures are based on those submitted to the AEUB plus an estimate of the costs associated with the expected new 500 kV line between Edmonton and Calgary.
- Distributions paid to AILP are equal to 30% of net income.
- Free cash flow deficits are 100% debt financed.

Outcomes:

- Under this scenario, ALP would record significantly larger than projected free cash flow deficits, which, when combined with 100% debt financing, would result in a material deterioration in ALP's financial profile.
- Given the nature of the projected capital expenditures (i.e. those required to maintain the reliability and efficiency of the Alberta electricity market), ALP would not be in a position to significantly reduce capital expenditures.
- ALP's sponsors, through AILP, would have to provide equity injections in order to maintain the current rating.

LONG-TERM DEBT MATURITIES AND BANK LINES

Term debt maturities by fiscal year as at July 31, 2004

	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010 & beyond
($ millions)	0	0	0	0	100.0	0	410.0

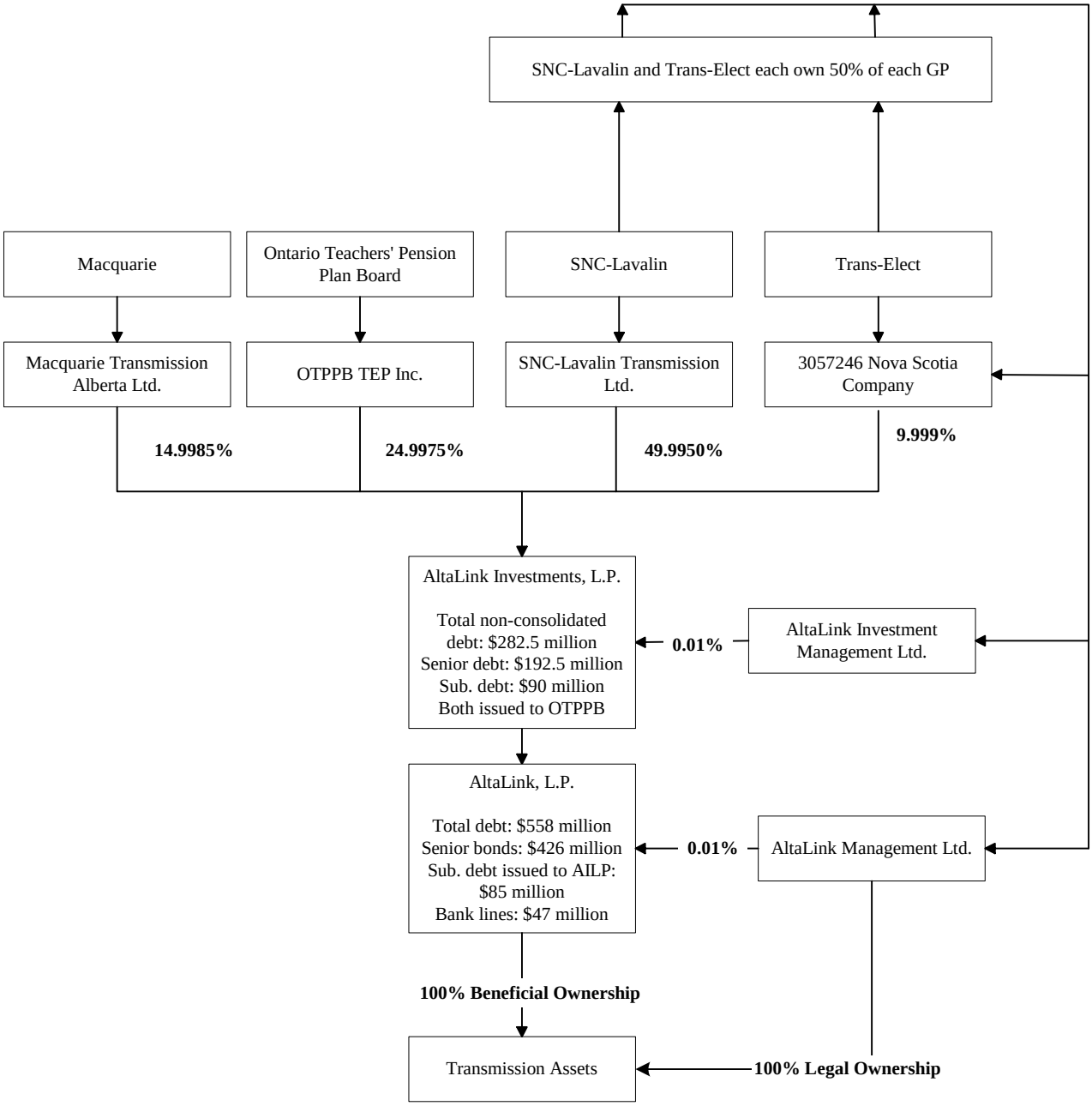
Summary:

- In late 2003, ALP refinanced its remaining $125 million senior bridge facility through a re-opening of its Series 03-2 5.43% Senior Secured Bonds due June 5, 2013.
  - ALP currently has $425 million outstanding in senior secured bonds.
- ALP also has $85 million in subordinated debt, maturing in 2012, issued to AILP.
  - Non-payment of either interest or principal on the subordinated debt does not trigger an event of default.
- ALP has a $185 million, 364-day revolving bank facility (maturing in May 2007) for working capital purposes and to temporarily finance capital expenditures until it is cost effective to refinance with long-term debt.
  - Under the terms and conditions, the credit facility cannot be used to refinance existing debt.
  - The credit facility ranks pari passu with the Senior Secured Bonds.
- At July 31, 2004, ALP had $46.9 million outstanding on the credit facility.
  - ALP had essentially no amount outstanding in letters of credit as at July 31, 2004.

Outlook:

- ALP has no refinancing requirements over the medium term.
- However, it will have to access the debt capital markets to fund a portion of its large capital expenditure program.

CURRENT CORPORATE STRUCTURE



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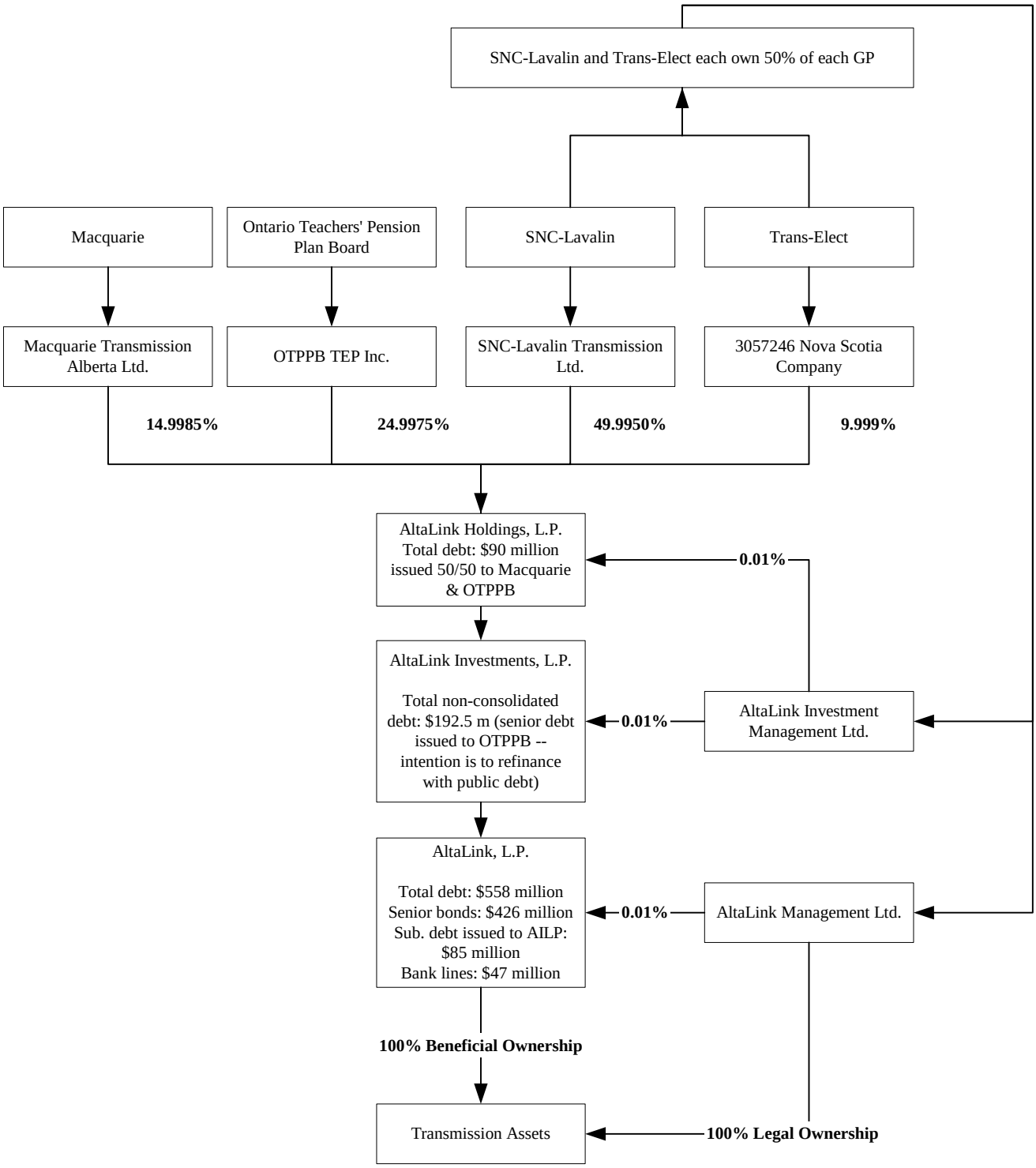
PROPOSED NEW CORPORATE STRUCTURE



- A corporate reorganization is being proposed to strengthen the financial profile of AILP by converting the subordinated debt issued by the sponsors to equity and moving the subordinated debt to the newly created L.P., AltaLink Holdings, L.P.
- A default on the subordinated debt at AltaLink Holdings, L.P. will not create a default on any of AILP's or ALP's debt.

AltaLink, L.P.

Balance Sheet

($ millions)	As at	As at April 30			As at	As at April 30	
Assets	July 31, 2004	2004	2003	**Liabilities and Equity**	July 31, 2004	2004	2003
Cash and short-term investments	0.81	2.30	0.00	Short-term debt	0.17	0.21	421.75
Accounts receivable	21.91	17.06	16.78	A/P + accr'ds	22.36	38.19	31.42
Inventories	0.86	0.96	0.80	Regulatory & other liabs.	1.72	0.39	6.98
Prepaids	2.38	1.35	1.09	L.t. debt due in one yr.	0.00	0.00	0.00
Regulatory assets	0.00	0.93	0.00	**Current Liabilities**	24.24	38.79	460.15
Current Assets	25.96	22.61	18.67	Reg. & environ. liab.	181.08	182.34	140.74
Net fixed assets	874.26	871.29	804.55	Other liabilities	2.57	2.12	1.84
Accrued pension benefit asset	2.92	2.94	3.25	Long-term debt	473.09	459.15	15.20
Other assets and deferred charges	18.28	19.62	12.14	Subordinated debt	85.00	85.00	85.04
Goodwill	202.07	202.07	201.83	Shareholders' equity	357.51	351.13	337.47
Total	1,123.49	1,118.53	1,040.44	**Total**	1,123.49	1,118.53	1,040.44

Ratio Analysis	12 mos. ended	For the year ended April 30		
Liquidity Ratios	July 31, 2004	2004	2003	2002
Current ratio	1.07	0.58	0.04	0.05
Acc. depreciation/gross fixed assets	10.8%	9.8%	5.2%	0.0%
Cash flow/total debt (1)	14.0%	14.7%	14.8%	n/a
Cash flow/total adj. debt (2)	16.0%	16.8%	17.0%	n/a
Total debt/EBITDA	5.12	5.47	4.79	n/a
Cash flow/capital expenditures	1.00	0.95	1.09	n/a
% debt in capital structure (1)	61.0%	60.8%	60.7%	60.1%
% adj. debt in capital structure (2)	53.5%	53.2%	52.8%	60.1%
Average coupon on long-term debt	5.10%	5.10%	n/a	n/a
Deemed common equity	35.0%	34.0%	34.0%	n/a
Distributions payout	40.4%	48.8%	96.6%	n/a
Coverage Ratios				
EBIT interest coverage	1.98	1.86	2.04	n/a
EBITDA interest coverage	3.52	3.18	3.75	n/a
Fixed-charges coverage	1.98	1.86	2.04	n/a
Profitability/Operating Efficiency				
Operating margin	38.2%	37.8%	38.9%	n/a
Net margin (before extras.)	18.8%	17.1%	20.0%	n/a
Return on average common equity	8.8%	7.7%	9.0%	n/a
Rate base - mid-year ($ millions)	671.8	671.8	654.1	n/a
Approved ROE	9.60%	9.40%	9.40%	n/a

(1) Includes subordinated debt as 100% debt.

(2) Subordinated debt given 80% equity treatment.

Credit Rating Report

FortisAlberta Inc.

Report Date: September 22, 2004
Press Released: September 22, 2004
Previous Report: August 6, 2003

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RATING

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Confirmed	Senior Unsecured Debt

RATING HISTORY	Current	2003	2002	2001	2000	1999	1998
Senior Unsecured Debt	A (low)	A (low)	"A"	"A"	NR	NR	NR

RATING UPDATE

The rating on FortisAlberta Inc. ("FortisAlberta" or the "Company") is confirmed at A (low), as performance remains in line with DBRS's expectations. The Company was downgraded in July 2003 from "A" as a result of the Alberta Energy Utility Board's ("AEUB") 2002-2003 rate decision (the "2003 Decision"). The 2003 Decision did not significantly impact net income as customer rates were reduced in line with the reduction in depreciation expenses; however, it had significant negative effects on operating cash flow and certain coverage ratios. Over the medium term it is expected that free cash flow deficits will continue, and FortisAlberta will have to rely on its ultimate parent, Fortis Inc. ("Fortis"), for equity injections in order to maintain the deemed capital structure.

The outlook on FortisAlberta remains stable over the medium term. The lower fixed-charges coverage ratio for the 12 months ended June 30, 2004, is a result of higher interest expense on inter-company debt, repaid in May 2004, that was not fully recovered in the AEUB-approved rates. On a positive note, FortisAlberta intends to file its first comprehensive depreciation study with the AEUB in 2005, which could offset some of the impact of the 2003 Decision on its operating cash flows by recovering some of the lost depreciation expense via higher depreciation rates. Also positive was the July 2004 generic cost of capital decision by the AEUB, which should bring more consistency and stability to the regulatory process, minimizing the perceived subjectivity of regulatory decisions. The AEUB-approved regulatory capital structure for FortisAlberta is 63% debt/37% equity, somewhat lower than the previously approved 60% debt/40% equity, with a return on equity (ROE) of 9.60% for 2004; however, FortisAlberta intends to maintain its overall capital structure at a more conservative 60% debt/40% equity.

Key challenges facing FortisAlberta over the medium term include: (1) significant ongoing capital expenditures which, when combined with the currently lower depreciation rates, will result in continued free cash flow deficits; (2) integrating the culture of the recently acquired FortisAlberta with the Fortis group of companies; (3) strengthening relationships with the AEUB and customer groups, which have historically been perceived as adversarial, with more transparency and openness on the part of FortisAlberta.

Although the $83 million EPCOR claim is still outstanding, FortisAlberta has filed a Statement of Defence (on February 17, 2004) and feels that the claim is without merit and would not have a material impact on the Company's operations.

The Company remains supported by its operating characteristics, specifically that it is a regulated electricity distribution business and faces limited forecast risk, which provides for relatively stable income. While the 2003 Decision did have a material impact on FortisAlberta's cash flows, the new owner, Fortis, is financially capable of providing the required equity injections to maintain a stable financial profile.

RATING CONSIDERATIONS

Strengths:

- Involved exclusively in regulated electricity distribution
- Minimal forecast risk due to limited sensitivity to weather
- Favourable franchise area in Alberta

Challenges:

- Reduced operating cash flows; free cash flow deficits
- Cumbersome regulatory environment with material lags
- Low regulated rates of return compared to U.S. utilities
- Negative impact on earnings and ROE due to an inability to recover all income taxes in customer rates

FINANCIAL INFORMATION

	12 mos. ended	For the year ended December 31			
	June 30, 2004	2003	2002	2001	2000*
Fixed-charges coverage (times)	1.85	2.22	3.03	1.97	1.87
% total debt in capital structure	55.9%	57.6%	57.2%	56.3%	69.3%
Cash flow/total debt	13.1%	8.5%	14.9%	28.4%	5.9%
Cash flow/capital expenditures (times)	0.46	0.33	0.62	1.19	0.78
Net income (before extras.) ($ millions)	21.8	26.6	21.3	12.1	(1.7)
Operating cash flow ($ millions)	51.4	34.6	60.6	114.3	35.0
Return on avg. common equity (bef. extras.)	7.2%	8.8%	6.9%	4.2%	(0.7%)
Electricity throughputs (GWh)	14,025	13,522	13,212	12,642	7,874

* For four months ending December 31.

THE COMPANY

FortisAlberta (formerly Aquila Networks Canada (Alberta) Ltd. or "ANCA") began operating in September 2000, following the acquisition of the Alberta-based electricity distribution and retail assets of TransAlta Utilities Corporation. The retail electricity operations were subsequently sold to EPCOR Utilities Inc. The franchise region is located in central and southern Alberta. FortisAlberta is ultimately a wholly owned subsidiary of Fortis, a Canadian public holding company focused primarily on electric utility operations in Canada, the Caribbean, and the U.S.

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REGULATION

- FortisAlberta is regulated by the AEUB based on a cost of service methodology.
- During 2002 and up to July 31, 2003, the Company had been collecting revenue based on 2001 approved rates and interim riders.
- The 2003 Decision was issued on July 4, 2003, and:
  - Lowered the Company's depreciation rate from over 5% to about 3.5%, retroactive to January 1, 2002;
  - Extended the useful life of the assets and increased their salvage value, resulting in a reduction in depreciation for 2002 and 2003 of $26.6 million and $38 million, respectively.
- FortisAlberta expects to file a comprehensive depreciation study with the AEUB in 2005.
- FortisAlberta intends to file a general tariff application in Q4 2004 to establish 2005 rates, with a decision from the AEUB expected in mid-2005.
  - FortisAlberta's existing rates were established August 1, 2003, and have continued in 2004.

Generic Cost of Capital:

- In late 2002, the AEUB decided to call a generic hearing to consider cost of capital matters for utilities under its jurisdiction, including FortisAlberta.
  - The AEUB rendered its decision on July 2, 2004, establishing equity ratios for the transmission and distribution utilities, as well as a common ROE, for 2004, of 9.60%;
  - The ROE will be adjusted annually, beginning in 2005, by 75% of the change in the forecast long-Canada bond yield.
- For a fully taxable electric distribution company such as FortisAlberta, the deemed equity ratio is 37%.
- DBRS views this hearing favourably as it should reduce some of the regulatory lag in the future, as a portion of FortisAlberta's cost components are pre-established.

RATING CONSIDERATIONS

Strengths: (1) FortisAlberta operates exclusively as an electricity distributor, which is regulated, generally stable, and relatively low risk. The regulatory framework for the distribution business is currently based on a cost of service methodology, which typically provides for a high degree of long-term earnings, cash flow, and financial stability. Financial leverage is expected to remain within the recently approved regulatory guidelines of 63% debt/37% equity, although the Company has indicated it intends to maintain a more conservative 60% debt/40% equity ratio for the overall entity. Regular monitoring by the AEUB of regulated utilities in Alberta ensures they are operating within the regulatory framework and this minimizes the risk of a parent company stripping the capital out of its regulated operating companies.
(2) The demand for electricity in Alberta, and more specifically for the Company, is only moderately sensitive to changes in the weather because the majority of the province uses natural gas for heating purposes and air conditioning is not required in the summer months to the same extent as in other jurisdictions. As a result, the Company faces minimal risk in terms of its demand forecast being significantly different from actual demand. This increases the stability of the Company's earnings and cash flow.
(3) The Alberta economy remains among the strongest in Canada, both fiscally and economically. However, given the energy-based nature of the economy, growth tends to be more volatile. The strong economic fundamentals of the Province should continue to have a positive impact on the Company's electricity throughputs and, consequently, its earnings and cash flow.

Challenges: (1) A major result of the 2003 Decision was the reduction in FortisAlberta's depreciation rates retroactive to January 1, 2002, and, consequently, the amount of depreciation expense that can be recovered through customer rates. As a result, depreciation expense was reduced significantly for 2002 and 2003. This will continue to impact operating cash flows on an ongoing basis. While FortisAlberta intends to file a comprehensive depreciation study in 2005, the weaker operating cash flows, when combined with continued capital expenditures of about $110 million per year over the medium term, will result in recurring free cash flow deficits and a further incurrence of debt financing.
(2) Alberta-based utilities have historically been burdened by material time lags associated with the regulatory process, adding to the cost, complexity, and uncertainty inherent in the system. Regulatory decisions were often delivered well after the fiscal period in question, resulting in charges against the current year's earnings to reflect prior-period adjustments (e.g. the 2002-2003 rate decision was rendered in February 2003). The process in Alberta is among the most adversarial in Canada, with intervener groups frequently dragging out the hearings for extended periods, while the applicant (and ultimately customers, through rates) is required to pay the costs of these groups. With the establishment of the generic cost of capital in July 2004, regulatory approval should be more streamlined and efficient, resulting in somewhat reduced regulatory lag.
(3) In Alberta, as well as in many other jurisdictions in Canada, the rates of return allowed by regulators have been low in recent years, largely as a result of the low interest rate environment. This has had a negative impact on earnings and cash flow. In addition, the allowed ROEs are significantly below those allowed for similar operations in the U.S. This acts as a disincentive for investors to allocate capital to Canadian utilities because they can earn higher rates of return in the U.S. from businesses having similar risk profiles.

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(4) The Company's net capital asset amount used for income tax purposes is lower than that allowed for regulatory purposes. The impact of this is that the Company must pay higher income taxes than it is allowed to recover through customer rates to offset the higher income taxes. As a result, the Company's cash flows, reported net earnings, and ROE are lower than they would otherwise be.

EARNINGS AND OUTLOOK

($ millions)	12 mos. ended June 30, 2004	For the year ended December 31 2003 (3)	2002 (3)	2001	2000R (1)
Total revenues	220.7	213.8	258.2	253.1	78.8
EBITDA	112.8	113.7	158.1	156.6	43.5
EBIT	67.2	69.1	75.5	75.3	16.6
Gross interest expense	36.4	31.1	24.9	38.2	8.9
Net interest expense	36.4	31.1	24.9	37.9	8.7
Pre-tax income	30.8	38.0	50.6	37.4	8.0
Net income (bef. extras.)	21.8	26.6	21.3	12.1	(1.7)
Net income (avail. to common) (2)	21.8	(53.4)	27.5	12.1	(1.7)
Return on avg. common equity (bef. extras.)	7.2%	8.8%	6.9%	4.2%	(0.7%)

(1) For four months ending December 31.

(2) For 2002, figure excludes a $10.3 million (pre-tax) favourable prior period regulatory decision.
For 2003, figure excludes $80 million goodwill impairment charge.

(3) For 2003, revenues, depreciation/amortization, and income tax expense are adjusted to remove the 2002 impact of the 2003 Decision (which was included in 2003 reported results). Figures for 2002 were not adjusted and reflect previously approved depreciation rates.

R = Restated.

Volume Throughputs & Customers	12 mos. ended June 2004	For the year ended December 31 2003	2002	2001	2000*
Electricity sales (GWh)	14,025	13,522	13,212	12,642	7,874
Number of customers	400,680	391,039	387,186	376,334	367,746

* For four months ending December 31.

Summary:

- Higher net income (before extraordinary items) for 2003 is a result of:
  - An increase in the rate base and growth in customer demand, as well as an additional $5.8 million in revenues related to a rate tariff that was previously collected, but not recognized in revenues until 2003.
- The most significant impact of the 2003 Decision was the reduction in FortisAlberta's depreciation rate and thus the amount of depreciation that FortisAlberta is allowed to recover in customer rates.
  - While this did not have a direct effect on FortisAlberta's net income, as customer rates were adjusted accordingly, it did affect operating cash flows.
- DBRS has adjusted various items in the 2003 income statement to remove the retroactive impact of this decision; 2002 results remain unadjusted, as reflected by the higher revenues.
- For the 12 months ended June 30, 2004, net income was lower due to higher interest expense incurred during the first six months of 2004.
  - Given that rates in 2004 have been maintained at their 2003 levels, the higher interest costs were not recovered in rates.
  - Also, the inter-company loans, repaid in May 2004, carried significantly higher rates of interest than market, resulting in higher interest expenses for these periods.

Outlook:

- It is expected that FortisAlberta's EBIT and net income will remain relatively stable over the medium term.
  - Some growth is expected to come from increases in both the customer base and rate base.
- The recent generic cost of capital decision should ensure that regulatory decisions are more streamlined and less burdened by regulatory process, as a debt/equity structure and ROE for rate-setting purposes are already pre-determined.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	12 mos. ended June 30, 2004	For the year ended Dec. 31 2003	2002	Sensitivity Analysis Year 1	Year 2	Year 3
EBITDA	112.8	113.7	158.1	102.3	102.3	102.3
Net income (bef. extras./one-time items)	21.8	26.6	21.3	16.1	11.5	7.3
Depreciation and amortization	45.6	44.6	82.6	56.2	61.9	67.0
Other non-cash adjustments	(16.1)	(36.6)	(43.3)	0.0	0.0	0.0
Operating Cash Flow	51.4	34.6	60.6	72.3	73.4	74.3
Capital expenditures	(111.9)	(103.8)	(97.4)	(110.0)	(110.0)	(110.0)
Common dividends	0.0	0.0	(0.3)	0.0	0.0	0.0
Gross Free Cash Flow	(60.6)	(69.2)	(37.1)	(37.7)	(36.6)	(35.7)
Working capital changes	(50.8)	(91.4)	94.4	0.0	0.0	0.0
Collection of regulatory cost deferral*	95.0	158.5	153.1	0.0	0.0	0.0
Free Cash Flow	(16.4)	(2.0)	210.4	(37.7)	(36.6)	(35.7)
Other investments	0.0	0.0	4.1	0.0	0.0	0.0
Net debt financing	(42.5)	1.8	(176.2)	37.7	36.6	35.7
Net equity/preferred share/other	46.9	46.9	(38.3)	0.0	0.0	0.0
Net change in cash	(12.0)	46.6	0.0	0.0	0.0	0.0
Total Debt	393	409	407	430.7	467	503.1
% debt in the capital structure	55.9%	57.6%	57.2%	57.6%	58.7%	60.0%
EBITDA/interest coverage (times)	3.10	3.65	6.34	5.2	4.75	4.38
EBIT/interest coverage (times)	1.85	2.22	3.03	2.35	1.88	1.51
Fixed-charges coverage (times)	1.85	2.22	3.03	2.35	1.88	1.51
Cash flow/total debt	13.1%	8.5%	14.9%	16.8%	15.7%	14.8%

For the sensitivity analysis, debt is based on June 30, 2004, figures as that represents the current capitalization structure, given the acquisition by Fortis.

Capex projections are based on Company forecasts. All free cash flow deficits are assumed to be debt financed.

* 2000 Pool Price Deferral Account.

Summary:

- The 2003 Decision substantially lowered depreciation rates, with depreciation expense falling by over $30 million between 2002 and 2003.
  - The lower depreciation expense and large non-cash adjustments, comprised primarily of provisions for future income tax and deferred charges, contributed to lower operating cash flows for 2003 and for the 12 months ended June 30, 2004.
- As such, operating cash flow has been insufficient to fund capital expenditures resulting in gross free cash flow deficits.
  - While collection of the 2000 Pool Price Deferral Account mitigated the free cash flow deficit in 2003 and for the 12 months ended June 30, 2004, it was largely collected by 2003 and is not expected to play a significant role in reducing the free cash flow deficits going forward.
  - The regulatory cost deferral stems from the period when FortisAlberta also retailed electricity and was subject to commodity costs. During 2000, the pool price charged to FortisAlberta exceeded the AEUB-approved rates that the Company could charge customers, resulting in the Company incurring expenditures that far exceeded the revenues received. The Company was directed to recover these deferred charges from 2001 to 2003.

Outlook:

- As a result of the AEUB's decision, which reduced FortisAlberta's depreciation rate, its operating cash flows will remain significantly lower over the medium term.
- Given FortisAlberta's large capital expenditure program of about $110 million per year over the medium term, the Company is expected to record significant free cash flow deficits, at least until 2008.
- It is expected that the free cash flow deficits will be funded through a combination of debt and equity contributions from the parent, Fortis, such that the capital structure of the overall entity is maintained at 60% debt/40% equity – more conservative than the deemed 63% debt/37% equity.
- Key coverage ratios will remain lower as a result of the 2003 Decision, however, they should remain within the range acceptable for the current rating.
- The comprehensive depreciation study, which FortisAlberta expects to file with the AEUB in 2005, could provide some recovery of depreciation expense if approved, which would reduce free cash flow deficits over the medium term.

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Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used are based neither upon any specific information provided by the Company, nor any expectations that DBRS has concerning the future performance of the Company.

Assumptions:

- Year-end 2003 EBITDA is reduced by 10% and remains flat thereafter.
- Annual capital expenditures are $110 million and the dividend payout remains at zero.
- Free cash flow deficits are 100% debt financed.
- Depreciation expense levels remain as per the 2003 Decision.
- No further regulatory deferral collections/refunds.

Outcomes:

- The recovery in FortisAlberta's interest coverage and cash flow-to-debt ratios during Year 1 are the result of higher operating cash flows and lower interest expense.
  - While they deteriorate slightly over the medium term, these ratios still remain acceptable for the current rating.
- FortisAlberta is expected to continue generating significant free cash flow deficits.

LONG-TERM DEBT MATURITIES AND BANK LINES

Summary:

- On May 31, 2004, as a result of the sale of ANCA to Fortis, the Company retired the $230 million long-term inter-company debt, and the $20.5 million short-term inter-company debt, as well as the $142.1 million bank loan arranged by CSFB. This debt was replaced with:
  - A $393 million unsecured bank bridge loan, fully drawn; and
  - A $100 million syndicated extendible revolving credit facility, maturing May 13, 2005 (there are no amounts currently outstanding under this facility).

Outlook:

- The Company's $100 million credit facility should provide sufficient liquidity to meet any short-term funding requirements.
- The Company is looking to refinance the $393 million bridge facility in the capital markets.
  - FortisAlberta plans on issuing the debt in two tranches: a ten-year tranche and a 30-year tranche.
  - Exact tranche sizes have not been confirmed as of the date of the publishing of this report.

DESCRIPTION OF OPERATIONS

- FortisAlberta is a regulated, electricity distribution company that has been operating since September 2000.
- The Company's franchise region is located in central and southern Alberta, in the suburbs surrounding Edmonton and Calgary as well as Red Deer, Lethbridge, and Medicine Hat.
  - FortisAlberta's distribution network comprises approximately 400,000 customers and approximately 60% of the Alberta distribution grid (as measured by circuit kilometres of line), with the bulk of their revenues derived primarily from industrial and residential customers, with some rural customers.

FortisAlberta Inc.

Balance Sheet

($ millions)	As at	As at December 31	
Assets	June 30, 2004	2003	2002
Cash and short-term investments	0.0	46.6	0.0
Funds on deposit	38.7	46.9	0.0
Acct. receivable	36.0	48.4	43.5
Regulatory cost deferrals	0.0	0.0	116.7
Inventories and prepaids	20.0	16.5	12.7
Current Assets	94.6	158.3	172.9
Net fixed assets	500.4	475.0	389.2
Regulatory deferral/deferred charges	2.1	0.0	12.9
Future income tax	13.5	14.2	3.0
Goodwill	189.3	189.3	269.3
Total	800.0	836.8	847.2

	As at	As at December 31	
Liabilities & Equity	June 30, 2004	2003	2002
Short-term debt	393.0	150.2	0.0
A/P + accr'ds/other	55.6	88.0	136.1
Regulatory liabilities	12.9	10.4	0.0
Regulatory cost deferral	28.6	29.0	0.0
Other debt due in one yr	0.0	28.4	144.5
L.t. debt due in one yr.	0.0	0.0	6.9
Current Liabilities	490.1	305.9	287.5
Deferred taxes/credits	0.0	0.0	0.0
Other debt	0.0	0.0	25.3
Long-term debt	0.0	230.0	230.0
Total liabilities	490.1	535.9	542.9
Shareholders' equity	309.9	300.9	304.3
Total	800.0	836.8	847.2

Ratio Analysis	12 mos. ended	For the year ended December 31			
Liquidity Ratios	June 30, 2004	2003	2002	2001	2000 (1)
Current ratio	0.19	0.52	0.60	0.60	0.67
Acc. depreciation/gross fixed assets	60.3%	60.7%	64.1%	62.5%	61.7%
Cash flow/total debt	13.1%	8.5%	14.9%	28.4%	5.9%
Total debt/EBITDA	3.49	3.59	2.57	2.57	13.54
Cash flow/capital expenditures	0.46	0.33	0.62	1.19	0.78
Cash flow-dividends/capital exp.	0.46	0.33	0.62	1.19	(1.02)
% debt in capital structure	55.9%	57.6%	57.2%	56.3%	69.3%
Average coupon on long-term debt	n/a	8.66%	8.66%	8.66%	n/a
Deemed equity	37%	40%	40%	40%	40%
Common dividend payout (before extras.)	0.0%	0.0%	1.3%	0.0%	n.m.
Coverage Ratios (2)					
EBIT interest coverage (times)	1.85	2.22	3.03	1.97	1.87
EBITDA interest coverage (times)	3.10	3.65	6.34	4.10	4.89
Fixed-charges coverage (times)	1.85	2.22	3.03	1.97	1.87
Profitability/Operating Efficiency					
EBIT margin	30.4%	32.3%	29.3%	29.7%	21.1%
Net margin (before extras.)	9.9%	12.5%	8.3%	4.8%	(2.2%)
Return on avg. common equity (bef. extras.)	7.2%	8.8%	6.9%	4.2%	(0.7%)
Allowed ROE	9.60%	9.50%	9.50%	#	n/a
GWh sold/employee	16.35	16.25	16.23	17.22	n.m.
Customers/employee	467	470	476	513	n.m.
Controllable costs/avg. customer ($) (3)	251.4	237.5	240.8	238.7	n.m.
Rate base ($ millions)	546	547	500	455	-

n.m.: not meaningful

(1) For four months ending December 31.

(2) Before capitalized interest, AFUDC, and debt amortizations. (3) Controllable costs include operating, maintenance, and administration.

#: negotiated settlement.

FortisAlberta Inc.

Income Statement	12 mos. ended	For the year ended Dec. 31			
($ millions)	June 30, 2004	2003 (3)	2002 (3)	2001	2000R (1)
Distribution revenues	207.298	202.078	248.092	398.346	431.381
Purchased power/transmission services	0	0.000	0.000	155.200	359.351
Net electricity revenues	207.298	202.078	248.092	243.146	72.030
Other income	13.412	11.691	10.144	9.966	6.811
Total revenues	220.710	213.769	258.236	253.112	78.841
Expenses:					
Operating, maintenance, & administration	100.735	92.873	93.228	89.835	32.880
Property taxes	7.218	7.177	6.889	6.687	2.483
Depreciation & amortization	45.577	44.583	82.578	81.304	26.831
Operating expenses	153.530	144.633	182.695	177.826	62.194
EBIT	67.180	69.136	75.541	75.286	16.647
Interest expense	36.398	31.142	24.924	38.196	8.893
Other financing charges	0.000	0.000	0.000	(0.300)	(0.223)
Interest/dividend income	0.000	0.000	0.000	0.000	0.000
Net interest expense	36.398	31.142	24.924	37.896	8.670
Pre-tax income	30.782	37.994	50.617	37.390	7.977
Income taxes (normalized)	8.935	11.372	29.295	25.242	9.675
Net income before extras./preferred dividends	21.847	26.622	21.322	12.148	(1.698)
Preferred dividends	0.000	0.000	0.000	0.000	0.000
Extraordinary/one-time items (2)	0.000	(80.000)	6.219	0.000	0.000
Net income	21.847	(53.378)	27.541	12.148	(1.698)

(1) For four months ending December 31.

(2) For 2002, figure excludes a $10.3 million (pre-tax) favourable prior period regulatory decision. For 2003, figure excludes $80 million goodwill impairment charge.

(3) For 2003, revenues, depreciation/amortization and income tax expense are adjusted to remove the 2002 impact of the 2003 Decision (which was included in 2003 reported results). Figures for 2002 were not adjusted and reflect previously approved depreciation rates. R = Restated.

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Attachment 5

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

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STANDARD &POOR'S

RATINGSDIRECT®

November 9, 2004

Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable

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Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable

Credit Rating: A/Stable/--

Rationale

On Nov. 9, 2004, Standard & Poor's Ratings Services affirmed its 'A' long-term corporate credit ratings on ATCO Ltd. (ATCO) and its subsidiaries, Canadian Utilities Ltd. and CU Inc. Standard & Poor's also affirmed its 'P-2(High)' Canadian national scale preferred shares ratings on ATCO and Canadian Utilities, its 'A-' senior unsecured debt rating on Canadian Utilities, its 'A' senior unsecured debt rating on CU Inc., and its 'A-1(Mid)' Canadian national scale CP ratings on Canadian Utilities and CU Inc. The outlook is stable.

The ratings on ATCO reflect its low-risk, monopoly-like gas and electricity delivery operations, economically healthy service territory, and generally favorable regulation. The conservative approach of management and the majority shareholders in the operation of the company and in the pursuit of growth opportunities further supports the ratings. Partially offsetting these strengths are ATCO's quasi-regulated, contracted, and merchant generation plants; higher risk of unregulated industrial activities; and a below-average financial profile compared with its global peers.

The monopoly-like nature of ATCO's gas and electricity transmission and distribution operations provides strong support to the company's business profile. Furthermore, it is expected that in the next few years, the company's Alta.-based regulated wires and pipes activities will continue to account for about half of ATCO's consolidated cash flow and more than 50% of its asset base.

ATCO's gas and electric utilities operate primarily in Alberta, which is viewed as an above-average market characterized by a strong provincial economy and economic fundamentals that compare favorably with national averages. Alberta's real GDP grew by 2.2% in 2003, just slightly ahead of the national average growth rate of 2.0% despite a number of challenges including the effect of the Bovine Spongiform Encepholopathy (BSE) outbreak on the agricultural sector and the sharp 22% appreciation in the Canadian dollar. Heavy exposure to the oil and gas sector could result in volatility; however, the province is expected to continue to grow in the next few years.

The Alberta Energy and Utilities Board (AEUB) regulates ATCO's gas and electric utility operations based on a cost-of-service/rate-of-return methodology. Standard & Poor's views the principal components of AEUB regulation as supportive. Specifically the regulator allows Alberta-based utilities to recover prudently incurred costs including operating and financing costs, allows the flow through of commodity and volume risk, and pre-approves the need for major capital expansion programs. The regulatory

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regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. Government interference in the regulatory process is minimal relative to other Canadian provinces. The province enjoys political stability, is strongly pro-business, and offers a very attractive investment environment with the lowest corporate and income taxes in Canada and no provincial sales tax.

ATCO's conservative approach to risk mitigation permeates its operations and is highlighted by its long-term growth strategy of balancing growth in its low-risk regulated operations and higher risk nonregulated operations. In the next few years, absent any significant acquisitions, growth in ATCO's nonregulated generation asset base is not expected to continue to outpace growth in the regulated business segment as it did in the past several years. Furthermore, ATCO's investments in generation are conservatively structured with limited commodity-risk exposure related to price paid for fuel or price received for electricity output.

Despite ATCO's conservative management approach, the operating risk surrounding its generation assets presents the potential for less cash flow stability relative to the regulated operations. Although the level of market and credit risk associated with the generation portfolio is managed, cash flows from this segment (expected to represent about 30% of consolidated cash flows) are exposed to higher operating risks than those derived from the regulated utility operations. The generation portfolio includes 1,312 megawatts (MW) governed by legislatively mandated power purchase agreements (PPAs); multiple independent power projects in Canada, the U.K., and Australia with long-term contracts and tolling agreements (1,065 MW); and a small proportion of merchant capacity (474 MW) located primarily in Alberta.

Also offsetting the strength and stability of its regulated utility operations are ATCO's service and industrial-based businesses, which are expected to account for about 20% of ATCO's cash flow. Contributing to the growth in this segment are the cash flows from a long-term service contract to provide billing services to retail customers in Alberta as well as an upswing in the company's cyclical industrial business activities.

The company's below-average financial profile stems from the thin equity layers and low returns of the regulated businesses as compared with global peers, and ATCO's aggressive financial policy for its nonregulated power generation businesses. The more aggressive financing of its regulated operations and generation assets is somewhat mitigated by the less asset-intensive and lower-leveraged nonregulated industrial businesses. Profitability is relatively low but stable over the long term, which is typical of utilities. In the next few years funds from operations (FFO) interest coverage is expected to continue to improve slowly but still remain weak for the rating at less than 4x on average. FFO interest coverage improved marginally in the last four years to 3.6x in 2003, up from 3.4x in 2001. FFO as a percent of average total debt could increase slightly to an average of 22%, up from 20% in 2003, but is also expected

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to remain aggressive for the rating. Growth opportunities, primarily in the electricity and gas rate base, are significant in the forecast period (5%-8% per year) and expected to dominate capital spending in the next two years absent any major capital acquisition. Capital spending in the regulated businesses is expected to average about C$400 million per year in the next several years. ATCO's total debt to capital, however, is expected to remain about 50% on a consolidated basis. Consolidated cash flows are expected to be sufficient to internally fund capital expenditures during the period 2005-2007. Access to common equity is constrained by management's preference to maintain the existing ownership structure; however, the company's financial flexibility is mildly supported by the ability to control growth-related capital spending in the generation portfolio and the potential for some small asset sales.

Liquidity.

ATCO's liquidity is adequate to support day-to-day operating needs, modest debt maturities, and expected capital expenditures of all companies in the group, given ATCO's relatively stable cash flow generation, available bank facilities, and its ability to access capital markets. Well-spread debt maturities in the range of C$160 million-C$250 million per year in the next three years are manageable and although consolidated cash flows in 2004 are not expected to be sufficient to fully fund capital spending in 2004 available bank lines are more than adequate to meet the shortfall. ATCO's consolidated liquidity is supported by a total of C$1.3 billion in operating lines of credit of which C$500 million serves to back stop CP programs at the subsidiary level. As of Sept 30, 2004, C$404 million remained available under the CP programs. With about C$140 million required to meet other funding obligations, of the C$800 million bank line capacity remaining, about C$660 million is available for meeting debt maturities and general corporate purposes. Furthermore, the company generally maintains a healthy level of cash and short-term investments that as of Sept. 30, 2004, totaled C$628 million, which would allow ATCO to take advantage of opportunistic asset acquisitions or withstand temporary financial setbacks.

Outlook

The stable outlook reflects a relatively stable, but moderately aggressive, financial profile that is adequately supported by ATCO's diversified utility operations, stable regulatory environment, and managed growth in higher risk nonregulated operations. The ratings, however, could be compromised by a large debt-financed acquisition or deterioration in ATCO's financial profile.

Ratings List

ATCO Ltd.

Corporate credit rating	A/Stable/--

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Preferred shares	
Global scale	BBB+
Canadian national scale	P-2(High)
Canadian Utilities Ltd.	
Corporate credit rating	A/Stable/A-1
Senior unsecured debt	A-
Preferred shares	
Global scale	BBB+
Canadian national scale	P-2(High)
Commercial paper	
Global scale	A-1
Canadian national scale	A-1(Mid)
CU Inc.	
Corporate credit rating	A/Stable/A-1
Senior unsecured debt	A
Commercial paper	
Global scale	A-1
Canadian national scale	A-1(Mid)

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STANDARD &POOR'S RatingsDirect

RESEARCH

Summary: AltaLink, L.P.

Publication date: 05-Jun-2006
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Credit Rating: A-/Stable/--

Rationale

The ratings on AltaLink, L.P. (AltaLink) reflect the company's strong business profile and average financial position. AltaLink's credit profile benefits from low-risk, electricity transmission assets, an attractive service area with favorable economic fundamentals, and the relatively supportive regulatory environment and market framework for transmission companies in the Province of Alberta. These strengths are offset by a financial profile constrained by regulatory directives, and pressured by capital funding requirements to meet significant network growth from 2006 to 2009.

Calgary, Alta.-based AltaLink is a regulated transmission company wholly owned by AltaLink Investments, L.P. (AILP; BBB-/Stable/--). Legal and structural ring-fencing measures permit the ratings on AltaLink to be insulated somewhat from its parent. A material change in the risk profile of either AltaLink or AILP could, however, have a direct effect on the ratings on both AltaLink and AILP. As of Dec. 31, 2005, including CP maturing in June 2006, AltaLink had total debt outstanding of about C$622 million.

AltaLink's monopoly transmission assets have inherently low operating risk. The transmission assets have demonstrated good reliability performance, in line with those of its Canadian peers. Furthermore, 60% of the existing asset base is less than 20 years old. As the company significantly expands its transmission infrastructure during the next several years, the age profile will improve further, as should AltaLink's operating efficiency.

AltaLink's transmission assets represented about 50% of the total circuit kilometers of Alberta's transmission grid and about 40% of Alberta's total transmission rate base as of 2005. AltaLink serves most of the more populated southern half of the province. Forecast growth in electricity consumption within the province, ranging from 2%-3% per year, is among the highest in Canada. The provincial economy's continuing strong prospects for growth in the near term contribute to AltaLink's growing rate base.

The predictability and security of AltaLink's regulated cash flows are enhanced by the cost-of-service/rate of return regulatory framework under which it operates. Furthermore, stable monthly revenue shields the company from cash flow volatility stemming from weather- or economy-induced variability of energy demand. The Alberta Electric System Operator, an agent of the Province of Alberta (AAA/Stable/A-1+), pays AltaLink for transmission services, thus mitigating the company's exposure to the credit profiles of AltaLink's end-users. The Alberta Energy and Utilities Board (AEUB), an independent regulatory body, provides oversight of all transmission assets in the province, and approves the company's transmission tariffs. Infrastructure upgrades and expansion projects are pre-approved by the AEUB and, once completed, are added to AltaLink's rate base, thus mitigating the risk of AltaLink under-recovering its investment.

Like many regulated utilities in Canada, AltaLink's average financial profile is constrained by a comparatively low approved ROE (8.93% in 2006) on a thin deemed equity base of 35%. AltaLink's adjusted funds from operations (FFO) interest coverage ratio improved in 2005 to 3.8x, from 3.3x as of Dec. 31, 2004 (based on an eight-month reporting period). Deferred revenues of C$7.5 million relating to

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2004 were recorded in 2005 net income. After eliminating the impact of the collection of these revenues, adjusted FFO interest coverage in 2005 would be 3.5x, in line with expectations. FFO-to-average total debt increased to 16% in 2005, from about 10% in 2004. Total debt-to-total capital, adjusted for operating leases, increased marginally to about 63%, from 61% in 2004. (The company changed its fiscal year-end to Dec. 31 from April 30 during 2004 to align its fiscal period with its regulatory period.) In 2006, AltaLink's key credit metrics are expected to remain comparable with 2005 results. In 2007-2009, however, during what should be a significant buildout period, the company's FFO interest coverage ratio is likely to weaken modestly and average closer to 3.5x, and FFO-to-average total debt is expected to average about 13%. This temporary weakening in cash flow metrics is due to a lag between taking on additional debt to partially fund new assets and collecting related revenues. AltaLink's total debt-to-total capital is expected to remain stable at 62% throughout this period, which is high but typical for Canadian regulated utilities and the company's international peer group.

The potential of almost doubling by 2009 the utility's 2004 rate base via capital expansion presents a significant challenge to AltaLink's operational performance and financial profile. During this period, capital spending is expected to average more than C$200 million per year, more than double historical annual capital expenditures of less than C$100 million. Although the incremental capital expenditure will be pre-approved by the AEUB, it carries execution risk and presents an issue of delayed receipt of regulated cash flow until the new transmission assets are in service. The costs plus a return, however, will be recoverable through regulated revenues during the life of the assets once they are in service. The company will not be able to internally fund total capital costs related to this significant expansion; net cash flow to capital expenditures is expected to average 40% in the next three years. In addition to new debt financing, there is also an expectation of timely equity injections from the ultimate shareholders of AILP to fund growth, ensure adequate liquidity, and prevent the deterioration of the financial profile of both AltaLink and AILP.

The ratings on AltaLink largely reflect the company's stand-alone credit quality, but remain linked with the rating on its owner. Legal and structural ring-fencing features and demonstrated regulatory oversight restrict AILP's ability to significantly increase cash distributions from AltaLink and provide a measure of protection to the operating company in the event of bankruptcy of AILP. The ring-fencing measures allow AltaLink to be rated more on a stand-alone basis rather than using Standard & Poor's Ratings Services' consolidated methodology; the ratings, however, remain somewhat constrained by the creditworthiness of AILP.

Liquidity

AltaLink's liquidity, which benefits from an expectation of modest unit-holder support, is expected to remain satisfactory during 2006. Together, FFO, which is expected to be about C$100 million in 2006, and the available capacity under the company's bank line and CP program, should be sufficient to fund forecast capital spending of about C$230 million (net of customer contributions) and distributions of about C$20 million in 2006.

The company established a C$200 million CP program in late 2005 that is backstopped by a C$200 million committed bank facility that expires in December 2008. As of March 31, 2006, C$73 million remained available under this program. Given the partnership's ongoing capital expansion program, there is an expectation that the debt under the CP program will be refinanced with a long-term debt issue sometime in 2006 to maintain AltaLink's liquidity at an acceptable level. There are no significant short- or long-term debt maturities at AltaLink until 2008. Also in late 2005, AltaLink reduced its C$185 million credit facility to C$85 million, which remained essentially undrawn at the end of first-quarter 2006.

Although AltaLink's accessible cash and cash equivalents remained nil as of March 31, 2006, the company had a meaningful restricted cash balance of C$55.7 million. The funds represent capital contributions from customers for construction of related customer-specific interconnections that will become available to AltaLink when the related projects are energized.

Outlook

The stable outlook reflects the expectation of full and timely equity injections from AltaLink's ultimate sponsors, in the 2006-2009 timeframe, to maintain a satisfactory capital structure at AltaLink by partially funding its capital expenditures. Failure of the sponsors to fulfill their commitment to inject cash on a timely basis would put immediate pressure on the ratings on both AltaLink and AILP. An outlook revision to

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negative or a downgrade could result from a significant and sustained inability to achieve both AltaLink's and AILP's forecast stand-alone financial profiles. An outlook revision to positive or an upgrade is unlikely in the medium term, given that AltaLink will continue to face significant financing and construction risk for the next several years. Furthermore, the ratings on AltaLink remain tied to the creditworthiness of AILP that is not expected to improve in the next several years.

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August 24, 2006

Union Gas Ltd.

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Union Gas Ltd.

Corporate Credit Rating

BBB/Developing/--

Financial risk profile (of parent Duke Energy Corp.)

Moderate

Debt maturities

2006 C$83 mil
2007 C$208 mil
2008 C$110 mil
2009 C$28 mil
2010 C$222 mil

Company contact

Julie Dill (1) 704-373-4332

Outstanding Rating(s)

Union Gas Ltd.	
Sr unsecd debt	
Local currency	BBB
CP	
Local currency	A-2
Pfd stk	
Local currency	BB+
Duke Energy Corp.	
Corporate Credit Rating	BBB/Positive/NR
Sr unsecd debt	
Local currency	NR
Sr secd debt	
Local currency	NR
Pfd stk	
Local currency	NR
Cinergy Corp.	
Corporate Credit Rating	BBB/Positive/A-2
Sr unsecd debt	
Local currency	BBB-
CP	
Local currency	A-2
Duke Capital LLC	
Corporate Credit Rating	BBB/Developing/A-2
Sr unsecd debt	
Local currency	BBB
CP	A-2

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Local currency	
Pfd stk	
Local currency	BB+
Duke Power Company LLC	
Corporate Credit Rating	BBB/Positive/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	BBB+
CP	
Local currency	A-2
PanEnergy Corp.	
Corporate Credit Rating	BBB/Developing/NR
Sr unsecd debt	BBB-
Westcoast Energy Inc.	
Corporate Credit Rating	BBB/Developing/--
Sr unsecd debt	
Local currency	BBB
Pfd stk	
Local currency	BB+
Cincinnati Gas & Electric Co.	
Corporate Credit Rating	BBB/Positive/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	BBB+
Sub debt	
Local currency	BB+
Pfd stk	
Local currency	BB+
Duke Energy Trading and Marketing, L.L.C.	
Corporate Credit Rating	BBB-/Stable/--
PSI Energy Inc.	
Corporate Credit Rating	BBB/Positive/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	BBB+
Pfd stk	
Local currency	BB+
Texas Eastern Transmission LP	
Corporate Credit Rating	BBB/Developing/--
Sr unsecd debt	
Local currency	BBB
Union Light Heat & Power Co.	

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Corporate Credit Rating	BBB/Positive/--
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	NR

Corporate Credit Rating History

Mar. 25, 2002	A+
Aug. 14, 2002	A
Jan. 31, 2003	A-
June 17, 2003	BBB+
Feb. 10, 2004	BBB

Major Rating Factors

Strengths:

- Large customer base that has attractive demographics and is resistant to economic cycles
- Strategic ownership of natural gas storage and transmission assets enhances competitive position
- Regulated cash flows

Weaknesses:

- High leverage associated with company's regulated capital structure
- Allowed ROE is relatively low compared with global peers

Rationale

The ratings and outlook on Union Gas Ltd., an Ontario-based natural gas distribution company, reflect the consolidated credit profile of its ultimate parent, Duke Energy Corp. (BBB/Positive/NR). The ratings on Union Gas have been equalized with those on Duke Energy, reflecting Standard & Poor's Ratings Services' consolidated ratings methodology. The assessment is further supported by the strategic nature of Union Gas within the wider Duke Energy group of companies. (For more information on Duke Energy, please refer to the full report published Aug. 18, 2006 on RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis.)

Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.3 million customers in northern, southwestern, and eastern Ontario. The company also owns and operates a transmission system (from Dawn, Ont. to Mississauga, Ont.) and the largest gas storage facility in Canada, with a working storage capacity of 150 billion cubic feet. As at June 30, 2006, Union Gas had total debt outstanding of about C$2.0 billion.

Duke Energy's business risk profile is '6' (satisfactory) and its financial risk profile is adequate. The company's business risk profile is supported by a stable, regulated electric utility, low-operating risk gas transmission and distribution, and gas-gathering operations that provide the bulk of cash flow. These strengths are offset by higher risk international operations, exposure to real estate operations, and uncertainty as to how the regulatory environment will evolve in Ohio after 2008.

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Duke Energy is planning to separate the electric business and natural gas operations effective Jan. 1, 2007, by spinning off the gas operations to shareholders. The new gas company will own all the U.S. and Canadian gas assets, while international and real estate operations will remain with the electric business, and Duke Capital LLC's (BBB/Developing/A-2) projected year-end 2006 debt balance of about US$3 billion is expected to move to the new gas company. Although the separation is expected to be largely credit neutral for the electric business, there is concern as to how the new gas company will be capitalized, especially in light of expected planned capital projects.

On a stand-alone basis, the key factors supporting Union Gas' strong business profile include its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism in place that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The Ontario Energy Board (OEB) regulates the utility, and all of Union Gas' revenues are derived from regulated activities providing a measure of stability to cash flows. Union Gas has a strong competitive position, with a monopoly on gas distribution in the markets it serves, mitigating any competitive threats. The competitive advantage of Union Gas' storage and transmission assets involves a combination of market liquidity and operating flexibility that enhances credit quality and helps the company manage natural gas inventories, providing the benefit of security of supply. The transmission system and storage facility connect to six major U.S. and Canadian pipelines servicing three large North American markets (Ontario, Michigan, and New York City). These strengths are partially offset by the volatility of natural gas prices, which can affect gas purchase costs for the company's operating requirements; volumetric risk resulting from changes in economic conditions and the price of alternate fuel sources, leading to possible fuel-switching by customers; and weather-induced variability of demand, as differences from the assumption of normal weather that is used in rate setting could result in volatility in gas consumption.

Duke Energy's consolidated financial risk profile is expected to remain adequate for the ratings and in line with recent financial performance, with adjusted funds from operations (AFFO) interest coverage of at least 4.2x in the medium term, AFFO-to-average total debt of at least 20%, and adjusted total debt that does not exceed 45% of total capital. Duke Energy has agreed to share about US$240 million in merger-related savings with ratepayers in North Carolina, South Carolina, Indiana, Ohio, and Kentucky during the next two years. Duke Energy's financial risk profile remains robust for the rating through Standard & Poor's sensitivity, which accounts for the company's providing all the agreed-upon savings to ratepayers while incurring all costs to achieve the merger, thereby receiving no cost savings benefit.

Union Gas' financial policy is determined by Duke Energy, but is also dictated by local regulatory directives. The provincial regulator, the Ontario Energy Board (OEB), allows only a 35% deemed equity component in the company's capital structure for rate-setting purposes, although an agreement was reached with the OEB in May 2006 to increase the equity component to 36% effective Jan. 1, 2007; therefore, leverage is on the high end for regulated utilities in North America. Union Gas' financial measures for 12 months ended Dec. 31, 2005, included AFFO interest coverage of about 3.2x, adjusted total debt to total capital at about 68%, and AFFO to total debt at about 16%. Revenue stability is achieved through a cost-of-service basis, where the rates are set to recover revenues equal to the forecast costs, including operating, maintenance, and administrative costs. To reduce the price volatility of its gas supply, Union Gas has a risk-management policy in place that has been accepted by the regulator.

Liquidity

Standard & Poor's Ratings Services' overall assessment of Union Gas' liquidity is tied to a consolidated view of Duke Energy's liquidity, which is adequate. Based on available credit lines and expected cash flow, Union Gas'

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liquidity, on a stand-alone basis, should meet cash outlay commitments and debt maturities for the next 12 months. Union Gas has a committed line of credit of C$400 million, which is primarily used as a backstop to its C$400 million CP program. As of June 30, 2006, the CP program was undrawn. Union Gas also has a C$25 million operating line of credit, of which C$22 million was available at June 30, 2006. Internally generated cash flows are sufficient to fund capital expenditures in the next several years.

Union Gas' liquidity is viewed on a consolidated basis with that of its ultimate parent, Duke Energy. Duke Energy's liquidity is adequate in light of the ongoing trading and marketing operations, as well as expected debt maturities of about US$1.6 billion annually until 2010. Total availability at March 31, 2006, through combined credit facilities was about US$5.3 billion, with US$3.1 billion at the Duke Energy subsidiaries (about US$2.2 billion unused capacity) and US$2.2 billion at the Cinergy Corp. (BBB/Positive/A-2) subsidiaries (US$1.35 billion unused capacity). Standard & Poor's expects that Duke Energy will resize the credit facilities as they mature to reflect the absence of its own derivative portfolio, while continuing to have sufficient liquidity to support Cinergy's trading and marketing operations until they are sold.

Based on Standard & Poor's liquidity adequacy ratio, which captures the effects of an adverse credit and market event on a company's primary sources of liquidity, Cinergy's coverage was just adequate during first-quarter 2006. The computation assumes a downside scenario in which Cinergy would have to post enough collateral to cover its entire negative mark-to-market exposure while accounting for an adverse movement in power and gas prices.

Cinergy also has an accounts-receivable sale program (US$406 million outstanding as of Dec. 31, 2005) that has a speculative-grade rating trigger.

Outlook

The developing outlook on Union Gas reflects the outlook on its parent, Duke Capital, which reflects concern as to how the proposed new gas company will be capitalized and funded upon completion of the planned spin-off. Although Standard & Poor's expects that the business risk profile of the new gas company will not be materially different from Duke Capital's current one, providing support to credit quality, additional information will be factored into the evaluation of the new gas company's credit profile as it becomes available.

Table 1

Duke Energy Corp.--Peer Comparison

	--Average of past three fiscal years--					
	Duke Energy Corp.	**FPL Group Inc.**	**Progress Energy Inc.**	**Exelon Corp.**	**Southern Co.**	**Dominion Resources Inc.**
Rating history	BBB/Positive/NR	A/Watch Neg/--	BBB/Positive/A-2	BBB+/Watch Neg/A-2	A/Stable/A-1	BBB/Stable/A-2
(Mil. US$)						
Sales	12,103.3	10,373.2	9,540.3	15,228.0	11,379.0	12,089.3
Income from continuing operations	527.4	871.6	763.7	1,195.0	1,534.3	1,191.7
Funds from operations (FFO)	3,389.4	1,806.5	1,593.3	4,094.3	3,140.1	3,267.8
Capital expenditures	2,151.3	1,400.9	1,456.3	1,990.3	2,067.5	2,139.0
Total debt	17,445.6	8,173.3	10,831.3	11,529.7	12,887.4	16,696.1

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Table 1

Duke Energy Corp.--Peer Comparison (cont.)

Preferred stock	0.0	1.7	93.0	87.0	526.7	1,090.0
Common equity	15,074.0	8,557.0	7,705.0	9,017.0	10,205.0	10,725.7
Total capital	33,146.2	16,731.9	18,665.7	20,648.0	23,619.1	28,501.8
Ratios						
Adjusted EBIT interest coverage (x)	2.5	2.6	2.0	3.6	3.6	2.5
Adjusted FFO interest coverage (x)	3.9	3.8	3.2	5.1	5.1	3.6
Adjusted FFO/avg. total debt (%)	18.8	19.1	13.2	29.4	23.7	17.0
Net cash flow/capital expenditure (%)	107.6	94.8	69.1	160.5	104.4	104.7
Adjusted total debt/capital (%)	52.6	52.8	61.4	59.3	56.4	61.0
Return on common equity (%)	3.1	9.8	10.0	13.3	14.5	10.8
Common dividend payout (%)	203.6	54.9	73.4	70.3	68.4	67.4

Table 2

Duke Energy Corp.--Financial Summary

		--Fiscal year ended Dec. 31--				
	TTM ended March 31, 2006	**2005**	**2004**	**2003**	**2002**	**2001**
Rating history	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Positive/A-2	BBB+/Negative/A-2	A/Negative/A-1	A+/Stable/A-1
(Mil. US$)						
Sales	11,177.6	11,030.6	22,503.0	22,080.0	15,663.0	18,197.0
Funds from operations (FFO)	3,782.7	3,519.6	5,108.3	4,092.4	4,530.0	3,590.7
Income from continuing operations	2,014.9	1,508.3	1,232.0	(1,003.0)	1,034.0	1,994.0
Capital expenditures	2,485.3	2,351.4	2,423.0	2,591.0	5,508.0	5,930.0
Total debt	16,530.5	16,015.4	19,366.5	22,466.6	24,261.1	16,132.3
Preferred stock	0.0	0.0	134.0	134.0	157.0	234.0
Common equity	16,552.0	16,439.0	17,927.0	15,449.0	16,848.0	14,935.0
Total capital	33,809.5	33,105.2	36,893.0	37,535.0	40,880.0	30,774.0
Ratios						
EBIT interest coverage (x)	3.6	3.3	2.4	1.9	2.2	4.4
FFO interest coverage adjusted (x)	4.8	4.5	4.6	3.8	4.8	5.3
FFO/avg. total adjusted debt (%)	23.4	21.6	26.4	17.5	22.4	22.3
Net cash flow/capital expenditures (%)	100.5	102.7	163.6	114.7	64.0	44.8
Total debt/capital (%)	48.9	48.4	51.9	59.3	59.0	51.9
Return on equity (%)	11.9	9.1	6.6	(7.0)	5.9	13.0

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Table 2

Duke Energy Corp.--Financial Summary (cont.)

Common dividend payout (%)	63.8	73.3	87.1	(101.8)	90.6	43.3

TTM--Trailing 12 months.

Table 3

Union Gas Ltd.--Financial Summary*

	--Average of past three fiscal years--	--Fiscal year ended Dec. 31--				
Rating history		BBB/Stable/--	BBB/Positive/--	BBB+/Negative/--	A/Negative/--	A-/Watch Pos/--
	Issuer	**2005**	**2004**	**2003**	**2002**	**2001**
(Mil. C$)						
Total revenues	1,920.0	2,084.0	1,841.0	1,835.0	1,589.0	1,926.0
Net income from continuing ops.	133.7	121.0	152.0	128.0	114.0	121.0
Funds from operations (FFO)	294.4	353.2	299.8	230.3	261.4	358.8
Capital expenditures	169.7	229.0	146.0	134.0	191.0	216.0
Cash and investments	20.3	0.0	0.0	61.0	0.0	0.0
Total debt	2,172.1	2,259.2	2,134.7	2,122.3	2,292.2	2,587.9
Preferred stock	105.0	105.0	105.0	105.0	105.0	119.0
Common equity	960.4	949.9	978.8	952.5	913.4	1,016.8
Total capital	3,237.4	3,314.0	3,218.5	3,179.8	3,310.5	3,723.7
Adjusted ratios						
EBIT interest coverage (x)	2.2	2.2	2.2	2.2	2.0	1.9
FFO int. cov. (x)	2.8	3.2	2.8	2.4	2.6	3.0
FFO/total debt (%)	13.6	15.6	14.0	10.9	11.4	13.9
Discretionary cash flow/total debt (%)	2.3	(2.0)	(3.2)	12.5	10.5	(11.9)
Net cash flow/capex (%)	110.7	101.8	116.3	119.6	47.8	133.7
Total debt/total capital (%)	67.1	68.2	66.3	66.7	69.2	69.5
Return on average equity (%)	12.6	10.4	13.4	11.7	10.2	10.9
Common dividend payout ratio (unadjusted) (%)	91.3	99.1	85.0	52.8	151.4	56.0

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STANDARD &POOR'S RATINGSDIRECT

RESEARCH

Industry Report Card:

Regulatory Rulings, M&A, And Fuel Cost Recovery Dominate Global Utilities Credit Environment

Publication date: 21-Nov-2006

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Commentary/Key Trends

Ratings activity for the global utility universe remained moderate over the past six months and was relatively balanced between upside and downside actions. Familiar themes continue to dominate the credit picture, including regulatory rulings, merger and acquisitions (M&A) activity, fuel cost recovery, accelerating capital expenditures for new generation projects, infrastructure improvements, and environmental requirements. Although these challenges and uncertainties may pressure future financial performance, overall, Standard & Poor's Ratings Services believes that the credit trend is likely to remain stable, based on the outlook distribution throughout the sector. While M&A activity and regulatory pressures are threatening ratings in Europe, the outlook for Latin American utilities is positive as companies continue to benefit from favorable market conditions.

In the U.S., rating actions were moving in a decidedly positive direction until early October, when political developments in Illinois resulted in downgrades of all of the state's electric utilities. The principal drivers of upside rating activity were organic developments such as stronger financial profiles and reduced business risk. Downward rating momentum can be traced to a difficult regulatory and political climate in Illinois and Maryland, weak financial metrics, and an increased emphasis on riskier unregulated ventures. Despite these challenges, the credit quality of U.S. utilities remains defined by the emphasis on core competencies, where risks are more familiar, but can still be considerable, including major pending regulatory decisions, the approaching end of lengthy rate freezes and industry transition periods in a few states, and the need for substantial infrastructure expenditures.

The Credit Drivers

Notwithstanding favorable market conditions in Europe, ratings remain under pressure due to a flurry of M&A deals and increasingly unsupportive regulation. The Canadian utility sector continued its trend of stable credit quality, reflecting a focus on the expansion of lower-risk, regulated core business, modest M&A activity, and the absence of any indication of further material market restructuring in any of the provinces. Although the outlook for the Australian utility sector remains predominately stable, liberal leverage at the regulated network businesses leaves companies susceptible to downward rating pressure in the event of underperformance. With the majority of Australian utilities in a growth mode and limited opportunities domestically, companies may become more acquisitive offshore. The lack of familiarity with the offshore region would heighten credit risk. In Latin America, utilities continue to benefit from favorable macroeconomic conditions.

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Despite some recent terminations in the U.S., specifically FPL Group Inc. (A/Stable/--) and Constellation Energy Group Inc. (BBB+/Negative/A-2), and Exelon Corp. (BBB+/Watch Neg/A-2) and Public Service Enterprise Group Inc. (PSEG; BBB/Negative/A-3), M&A activity remains a major credit driver around the globe, especially in Australia and Europe, with private equity funds driving some European transactions. With most of the deals heavily debt-financed, credit quality will likely suffer. Utilities in Europe and the U.S. are also under pressure to increase shareholder value. This is especially significant for utilities whose financial profiles are already somewhat weak for their ratings, leaving them susceptible to negative rating actions if their credit metrics deteriorate further.

Going forward, a very important dynamic for shaping the overall financial condition of the industry will be the quality of regulation. In general, uncertainty regarding rate-setting actions in the U.S., New Zealand, and Europe will weigh heavily on credit quality. In the U.S., regulatory uncertainty has emerged with the approaching end of lengthy rate moratoriums and industry transition periods in some states. There will also be requests for large amounts of rate relief to recover plant investment. Regulators are likely to be reluctant to authorize material rate hikes, although the cost pressures on many utilities could be significant as they struggle with attrition caused by years without a rate filing following restructuring legislation and regulatory rule making. High fuel costs, pension obligations, and health-care expenses further exacerbate these pressures.

Although no fundamental changes are expected from the transition to a national regulator in Australia from a state-based regulatory regime, the conversion creates an element of uncertainty. Regulatory frameworks across Canada allow for below-average ROEs that may reduce financial flexibility, as utilities face a challenging period of asset renewal and growth. As the financial profiles of many utilities in Western Europe continue to strengthen, the regulatory environment has become more restrictive, especially in Germany and Sweden. Meanwhile, the regulatory climate in Latin America and Eastern Europe appears to remain supportive of credit quality.

In the U.S., Europe, New Zealand, and Latin America, financial performance has modestly strengthened. This improvement can be traced to the ability of most companies to pass on to customers higher fuel prices, an extended period of favorable market conditions, deleveraging, costs containment, and the sale of unregulated noncore assets. However, this trend may stabilize or reverse, due to the effects of high energy costs and problems that could arise with fuel availability, the continuation of debt-financed M&A, and accelerating capital outlays for new generating capacity additions, diversity of natural gas supply, new pipeline, and liquefied natural gas projects. Accordingly, responsive and timely rate adjustments by regulators and credit supportive actions by management will be necessary to prevent a decline in measures of bondholder protection.

Healthy Market Sustains U.S. Credits

The main drivers of recent upside rating actions for U.S. utilities include enhanced liquidity and overall stronger financial profiles, better operating performance, reduced business risk, and sustained improvement in regulatory relationships, and refocused business strategies. The negative rating actions were attributable to an extremely challenging regulatory environment, subpar financial parameters, and increasing business risk related to investments outside the traditional regulated business. The handful of new CreditWatch listings can be traced to event risk; specifically, M&A announcements. Perhaps the most recent notable events in the U.S. were the dissolution of the merger agreements between Exelon Corp. and PSEG, and FPL Group Inc. (A/Stable/A-1) and Constellation Energy. The collapse of these mergers is directly related to political unrest during the approval process, highlighting the very real vulnerability of utilities to aggressive political initiatives. These failed attempts may negatively affect the potential for utility consolidation in the U.S.

The ratings distribution for the utilities sector in the U.S. remains entrenched in the 'BBB' rating category and about 53% of the sector carries a stable credit outlook. This level of rating stability reflects a fundamentally sound business model, and a reasonably steady financial performance. Much of the industry continues to emphasize their core competencies, where risks are more familiar, but can still be considerable, including major pending regulatory decisions, the approaching end of lengthy rate freezes and industry transition periods in a few states, the need for substantial infrastructure expenditures, fuel cost recovery in a relatively high-fuel-price environment, and gradually rising interest rates.

The merchant power sector witnessed very limited rating activity in third-quarter 2006. Standard & Poor's

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raised the ratings on Mission Energy Holding Co. and its subsidiaries one notch to 'BB-' to reflect the tighter relationship of the companies' credit quality to that of parent Edison International (BBB-/Stable/--) in light of Edison's expected but unspecified capital contributions over time. Otherwise, the only rating action was the placement of the 'B+' rating of Mirant Corp. and its rated subsidiaries on CreditWatch with negative implications, after the company announced that it would sell its Asian and Caribbean assets and use the proceeds to buy back stock. Generally, Standard & Poor's expects that a general consolidation of the merchant sector will result, despite the earlier failure of NRG Energy Inc. (B+/Stable/B-2) and Mirant to merge.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal prices have risen. Utilities operating under rate moratoriums, companies without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or which face significant regulatory lag, are also subject to reduced operating margins, increased exposure to cash flow volatility, and greater demand for working capital. Companies that are routinely granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. However, not all companies suffer from high fuel costs. Companies with significant nuclear and coal base-load capacity and midstream oil and gas operations are posting solid financial metrics, due to their generally low cost of production relative to gas-fired plants, which typically set the price of power in degregulated markets.

With few exceptions, regulatory outcomes have supported relatively strong credit characteristics for the utility industry. However, prospectively, regulators will be addressing large base-rate relief requests related to new generating capacity additions, environmental modifications on coal plants, and transmission and distribution (T&D) improvements. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes-significant cash flow drain, and reduces a utility's need to issue debt during construction. Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery.

A favorable development for credit quality is that many regulatory rulings related to the construction of new base load follow comprehensive settlement negotiations among utilities, commission staff, consumer advocates, and other major intervenors. Such an approach, which has occurred in Wisconsin, Iowa, Missouri, Kansas, and Colorado, limits the possibility of any subsequent review of utilities' expenditure decisions. Also supportive has been the adoption in certain states, such as Kansas and Indiana, and most recently in Missouri, of environmental-tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental-compliance equipment, without having to file a formal rate case. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges, rather than volume-based charges, the greater the support for credit quality.

Notwithstanding gradual improvement in financial measures over the past few years and the industry's current focus on traditional regulated utility operations, Standard & Poor's does not discount prospects for a return to business pursuits outside the core competencies of utility management. Inevitably, competition for capital and investor interest could again embolden companies to embrace growth strategies that would likely erode credit quality, absent protective structural and ring-fencing mechanisms. Efforts to reward shareholders through share repurchases or common dividend increases will also weigh on credit quality. These actions are especially significant for companies whose financial profiles are already somewhat weak for their ratings, leaving them susceptible to negative rating actions.

Favorable Conditions In Europe Tempered By M&A Pressure

Most major European utilities continue to benefit from favorable market conditions. Generators and vertically integrated power utilities, particularly in deregulated markets, have continued to benefit from robust power prices driven by high oil, gas, and carbon dioxide prices. Nevertheless, ratings remain under pressure primarily due to M&A activity, with nearly half of the top-20 utilities (ranked by debt issuance) on CreditWatch with negative implications or with a negative outlook. This M&A activity is likely to be boosted in the near term by any fallout from the ongoing battle to takeover Spain's Endesa S.A. (A/Watch Neg/A-1) and from the merger of Suez S.A. (A-/Watch Pos/A-2) and Gaz de France S.A. (GDF; AA-/Watch Neg/A-1+) in France and Belgium.

M&A activity has also affected smaller utilities, where not only utilities, but also private equity funds are

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acquisitive, with valuations increasing on regulated water and electricity assets alike.

M&A has remained a key ratings driver among the largest European utilities, but has not resulted in additional rating actions in recent months. Nevertheless, six major European utilities remain on CreditWatch due to M&A activity:

- E.ON AG (AA-/Watch Neg/A-1+) due to its planned acquisition of Endesa;
- Endesa due to its position as an acquisition target;
- Iberdrola S.A. (A+/Watch Neg/A-1) due to its agreement to acquire Endesa assets from the other bidder, Gas Natural SDG S.A. (A+/Watch Neg/A-1), if successful;
- GDF and Suez remain on CreditWatch with respect to their pending merger; and
- National Grid PLC (A/Watch Neg/A-1) remains on CreditWatch, pending the acquisition of U.S. operator KeySpan Corp. (A/Watch Neg/A-1).

Other major European utilities also affected by M&A activity include RWE AG (A+/Negative/A-1), which announced the sale of the largest U.K. water company, Thames Water Utilities Ltd. (BBB+/Watch Neg/A-2) to Kemble Water Ltd., a consortium led by Macquarie's European Infrastructure for £8.4 million including existing debt.

In Spain, the original timetable for the potential acquisition of Endesa by E.ON has been delayed, and timing for completion is uncertain. Numerous proceedings were launched by the various parties, in addition to the requirement for competing bids to run in parallel. The European Commission concluded that most of the Comision Nacional de Energia's conditions to approve the acquisition are illegal and requested explanations from the Spanish government. At the same time, Acciona S.A., the Spanish construction and investment company, is building a stake in Endesa, raising the acquisition price, which has so far been matched by E.ON.

Regulatory developments are likely to be a more negative factor, as European utilities' improved financial performance, due to high energy prices, attracts increasing scrutiny. The regulatory environment has become less supportive, particularly in Germany and Sweden.

In Germany, the new network regulator, Bundesnetzagentur, imposed significant tariff reductions. Initial cuts in tariffs of 18% for Vattenfall Europe Transmission (the third-largest German high-voltage grid operator), are achieved by reducing allowable asset values, the absolute ROE, and other costs. In Sweden, taxation on power generation has increased, while electricity network-distribution regulations have also become stricter. These adverse regulatory developments in Vattenfall's main markets were the key driver for our recent revision of its outlook to stable from positive. Further low- to mid-double-digit tariff cuts for various electricity and gas distribution operators have followed.

These conditions have also affected energy trading contracts, as a German Federal Court ruling forced E.ON to shorten the term of its wholesale gas sales contracts.

In France, which is traditionally supportive of its major utilities, the government granted GDF only a 5.6% increase in regulated supply tariffs, effective May 1, 2006, which does not cover the group's sourcing costs which negatively affected its cash flow by €331 million in the first half of 2006. Gas supply prices will now be reviewed on an annual, rather than quarterly, basis, increasing interyear liquidity needs. GDF's regulated electricity retail supply tariffs increased by only 1.7% from August 2006, which was the first since 2004. A further twist is that industrial electricity users who chose market-priced contracts can opt into a renewable, two-year period to tariffs capped at 30% above the regulated supply tariffs. Suppliers would be compensated by generators, in particular GDF. Such amendments will negatively affect GDF, as they will reduce the share of its highly profitable French sales at market prices. The group estimates that the mechanism will negatively affect its operating income. While the pressure from the EU is undoubtedly growing, it remains uncertain how the EU will implement the acceleration of competition and facilitate the drive to fully open the internal energy markets. Ratings could be affected by this move in the longer term, if significant restructuring of ownership or capital structures results.

The EU launched an investigation in June 2005 to assess the competitive conditions in the European gas

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and electricity markets, with a view to addressing the barriers hampering the development of a fully functioning and open EU-wide energy market from July 1, 2007. In February 2006, the EU published a preliminary report, with the final report expected to be published early in 2007. The preliminary report details the five main barriers to a fully functioning gas and electricity markets identified by the EU:

- A high degree of concentration in most European markets, with some incumbents continuing to enjoy dominant positions;
- Vertical integration of the largest players, meaning not only the ownership of T&D assets by most incumbents, but also in gas, the network of long-term contracts between gas producers and incumbent importers;
- Limited market integration, given the difficulty in securing available capacity on cross-border pipelines in gas, and insufficient interconnection capacity and long-term capacity reservations predating the market opening in electricity;
- Lack of transparency in the electricity wholesale market, but also of reliable and timely information on the gas markets; and
- Price formation mechanisms, which at present are not adequately robust and reliable.

The EU has launched a number of proceedings against 17 of the EU's 25 members (including France, Germany, Belgium, Spain, and Italy) for not fully incorporating directives on the full opening of energy markets to competition into national law.

Canada Credits Remain Solidly Investment Grade

The credit quality for the Canadian utility sector remains stable, despite an upcoming period of heavy capital spending. The sector remains solidly investment grade, with all issuers falling within the 'A' and 'BBB' ratings categories. The number of 'A' and 'A-' rated credits has remained unchanged in the past year. There has been some shuffling, both positive and negative, of ratings in the 'BBB' category related to company-specific developments. The Oct. 31, 2006 announcement by the federal Finance Minister of the government's intention to impose taxes in 2011 on Canadian "specified investment flow-through" entities, which include all of what are generally referred to as income trusts, has had a limited effect on creditworthiness in the sector in the near term. Two power trusts, anticipating equity issuance in the near term as part of financing of recent asset acquisitions, were put or remain on CreditWatch with negative implications, as management reviews financing plans under less-attractive equity market conditions. High capital requirements are expected to dominate the utility scene in Canada for the remainder of the decade. New electric and gas infrastructure (production and delivery) is required across the country to renew aging assets and meet increasing demand driven by domestic organic growth and increasing oil and gas exports. On the electricity side, multibillion-dollar transmission renewal and expansion has begun in Alberta and Ontario. Several key electric utilities have major new generation facilities under construction and are committed to more in the near future. Supplementing these large capital-intensive projects are large and small new independent power producer projects. For instance, a total of 3,600 MW of new generation (predominantly gas-fired) in Ontario alone is expected to be brought in-service in 2007 and 2008. More than C$10 billion in various capital-expenditure opportunities for new oil and gas pipelines over the next several years have been identified. However, it is unclear at this time what projects will actually be developed. Many of these projects relate to the burgeoning developing in the Alberta oil sands.

Related pressure on financial strength is not expected to affect credit quality in the sector. Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns. As a result, most companies will not generate sufficient internal cash flow to fully fund projected outlays during this expansion period. The bulk of capital to be spent, however, will become part of regulated rate base and, once complete, companies are expected to recoup their cost of capital and earn a modest ROE. Furthermore, debt raised to build new (nonutility) generation will generally enjoy the support of relatively stable cash flow from long-term contracts with solid government counterparties. Limited new merchant generation is anticipated, and only in Ontario and Alberta.

M&A Abounds In Australia

M&A activity continues to be the major credit driver for Australian utilities. On Oct. 6, 2006, shareholders of Alinta Ltd. (BBB/Negative/--) and The Australian Gas Light Co. (AGL; unrated) voted in favor of the proposed A$6.8 billion merger of AGL's infrastructure assets with Alinta and the subsequent separation of AGL Energy. As of result of the transaction, Standard & Poor's assigned a 'BBB' rating and stable outlook

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to AGL Energy, and affirmed the 'BBB' rating on the Alinta companies, including the AGL infrastructure business, which was renamed Alinta LGA Ltd. on Oct. 25, 2006. However, the outlook was revised to negative reflecting the company's restructuring and integration challenges, combined with its aggressive risk appetite.

Also pending is completion of the Diversified Utility Energy Trust's (DUET; BBB/Negative/--) A$429 million (29% equity) transaction in the consortium to purchase Duquesne Light Holdings Inc. (Duquesne; BBB/Watch Neg/--), which serves the greater Pittsburgh, Pa.-area. The transaction was announced on July 6, 2006. If approved by shareholders and regulators, the transaction should close in first-quarter 2007. DUET's credit quality will be unaffected by the completion of the transaction. With regard to privatization of government-owned electricity assets, in April 2006, the Queensland government announced the sale of the state's retail contestable electricity and gas assets. On Oct. 3, 2006, it was announced that the Australian Pipeline Trust was the successful bidder for the Queensland government's gas distribution business, Allgas for A$521 million, which represents a very high 1.7x multiple to Allgas' A$303 million regulated asset base value as of June 30, 2006. Other Queensland energy assets expected to be sold in 2006 include electricity and gas retailer Sun Retail and Powerdirect Australia, a second energy retailer. The outlook for the Australian utilities sector is stable, with nearly three-quarters of the rated entities possessing stable outlooks. Nevertheless, regulated network businesses remain aggressively financed, leaving little room in their rating for underperformance. With the majority of Australian utilities in growth mode and only limited opportunities domestically, a trend of companies becoming more acquisitive offshore is a distinct possibility. The lack of familiarity with the offshore regulation, markets, operations, and competitive environment can only heighten the credit risk of such transactions.

New Zealand Regulatory Environment Increasingly Uncertain

The regulatory environment in New Zealand has grown somewhat less uncertain, with the New Zealand Commerce Commission (NZCC) recently reaching several administrative settlements. In October 2006, Vector Ltd. (BBB+/Negative/--) reached an in-principle agreement on an administrative settlement with the NZCC. This follows the NZCC's August 2006 decision to publish an "intention to declare control" of Vector's electricity distribution services, reflecting its belief that Vector was earning excess returns. In September 2006, the NZCC and electricity distribution business, Unison Networks Ltd. (not rated), agreed to an administrative settlement that will result in a price cut effective December 2006.

Below-average hydrology and a lack of reserve power contributed to high wholesale electricity pool prices in early 2006. However, recent rains and snowmelt have alleviated the situation, with total storage up to 1,979 gigawatt-hours in mid-October 2006, an increase of 24% compared with the previous month. This has led to significant price relief, with average wholesale prices retreating back toward NZ$40 per megawatt-hour (MWh) in mid-October, compared with prices of NZ$160 per MWh in early April. By the same token, energy companies that are 'long' generation, such as Genesis Power Ltd. (Genesis; BBB+/Stable/--), Contact Energy Ltd. (BBB/Stable/A-2), and Mighty River Power Ltd. (BBB+/Stable/A-2), have experienced strong cash flow in 2006 because of the high electricity prices.

There have been some encouraging signs regarding additional gas sources in the short term. Most recently, the Pohokura field, with about 700 petajoules (PJ) of reserves, commenced commercial production in early September 2006. This field will complement the declining Maui field as it winds down over the next two to three years. In addition, an agreement has been reached to develop Kupe, the second-largest undeveloped field in New Zealand after Pohokura, with an estimated 281PJ of gas resource. The first gas is expected to be produced by mid-2009. Yet, New Zealand still faces a gas supply challenge over the medium term, as additional gas supplies are relatively modest, especially compared with the increasing demand for electricity (which is increasing at 2% to 3% annually). Furthermore, all the new gas supplies will be more expensive than the Maui gas on which New Zealand has long relied. Ratings stability is envisioned for New Zealand utilities. Very high average electricity prices during fiscal 2006 have generated strong cash flows to energy companies with surplus generation. However, uncertainty in the regulatory environment, particularly in the network sector, and uncertainty regarding additional gas supplies will continue to weigh on the sector's creditworthiness.

Latin American Momentum From Macroeconomic Conditions

The ratings trend for Latin American electric utilities remains positive, which has been the case since 2003. This upside momentum can be traced to good macroeconomic conditions, which has resulted in a relatively strong demand for power, stronger local currencies against the U.S. dollar, and better company

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access to very favorable financial markets. This healthy economic environment has not been affected by presidential elections in many countries throughout 2006 like Perú, Colombia, México, Brazil, and Ecuador. The combination of higher cash flow generation and favorable financial market conditions permitted many companies to deleverage, extend debt tenors, and reduce foreign exchange risk and interest rates on their outstanding financial debt. As a result, various utilities in the region have been upgraded. These mainly included Argentine electric utilities that completed debt restructuring following massive defaults in early 2002; Brazilian companies that benefited from the country's positive economic and financial environment; and Chilean power generators that benefited from higher regulated electricity prices triggered by the passage of a new regulation in May 2005.

Rating Activity

Table 1

Asia Pacific

Company/Rating/Comments	Analyst
AGL Energy (BBB/Stable/--)	
On Oct. 20, 2006, AGL Energy was assigned a 'BBB' rating and stable outlook. This followed a shareholder vote on Oct. 6, 2006, and the subsequent Federal court approval on Oct. 9, 2006, in favor of the proposed scheme of arrangement, meaning the merger and demerger between Alinta Ltd. and The Australian Gas Light Co. (AGL) became effective on Oct. 25, 2006. The remaining AGL infrastructure business forms part of the new Alinta corporate structure, and was renamed Alinta LGA Ltd. (BBB/Negative/--), also effective Oct. 25, 2006.	Mark Legge
Alinta Ltd. (BBB/Negative/--)	
The merger between Alinta Ltd. and AGL Energy was completed on Oct. 25, 2006, following shareholder approval on Oct. 6, 2006. The combination of the existing Alinta group companies with the AGL infrastructure businesses improves Alinta's overall business profile through the consolidation of stable and predictable cash flow from regulated and monopoly-like assets. Moreover, creditworthiness is enhanced by the increased geographic and market diversity that the new businesses bring to the Alinta group.	Peter Stephens
Contact Energy Ltd. (BBB/Stable/A-2)	
Contact Energy Ltd.'s 2006 financial performance was sound with funds from operations at NZ$408 million, moderately exceeding expectations. Highlighting the benefit of Contact's generation diversification, output increased by 10% over fiscal 2006, despite New Zealand's South Island experiencing the driest year in almost three decades. The company's thermal plant output rose more than 40%, which offset a 23% fall in hydro output. While high wholesale prices substantially benefited generation revenue, the negative impact on the company's retail operations due to a rise in electricity purchase costs was mitigated by a rise in electricity tariffs of 4%. Contact faces the dual and interrelated challenges of sourcing additional gas post-2010 to support its generation activities, and the associated pressure on margins as such gas will be more expensive and less flexible than the Maui 367 gas which ceases in 2009.	Mark Legge
Diversified Utility and Energy Trusts (DUET) (BBB-/Negative/--)	
DUET is part of a consortium seeking to acquire Pittsburgh-based electricity company Duquesne Light Holdings (DQE; BBB/Watch Neg/--). Completion of the equity-funded deal is expected in first-quarter 2007. DQE will end up being DUET's largest investment, placing pressure on DUET to deliver equity returns sufficient to compensate its unit holders that have funded this investment. If the transaction proceeds as expected, the investment in DQE will improve DUET's financial profile and add up to 1x cover to POWERS, increasing coverage to about 4x. DUET also faces the challenge of managing the expansion of the Dampier-to-Bunbury Pipeline, which is currently undergoing stage 4 expansion with the stage 5a expansion about to commence. However, the risks around this investment are diminishing, as a track record is established as the stage 4 expansion nears completion.	Richard Creed
Origin Energy Ltd. (BBB+/Stable/A-2)	
Origin Energy Ltd.'s cash flow metrics remained solid in fiscal 2006, with FFO to debt around 27%. Nevertheless, cash flow was below Standard & Poor's Ratings Services' expectations, primarily reflecting an 11% decline in exploration and production EBITDA, due to a 27% decline in Perth Basin oil production and delays in the BassGas Project. The Kupe Gas Project, in which Origin has a 50% share, received final investment approval in June 2006, with projected capital expenditures on the project having grown substantially to NZ$980 million. Completion is expected by mid-2009. While the company is estimating EBITDA growth for its Australian operations of 15% in fiscal 2007, it has indicated contributions from its 51% investment in Contact Energy may shrink as its subsidiary deals with the challenges of possibly lower wholesale electricity prices and increasing gas (input) prices.	Mark Legge
Canada	
Canadian Utilities Ltd. (A/Stable/A-1)	
In second-quarter 2006 (ended June 30), Canadian Utilities Limited reported year-over-year growth in earnings due primarily to higher contributions from its natural gas storage operations and higher contributions from the sale of natural gas liquids at Atco Midstream. The increased earnings were somewhat offset by an unfavorable tax reassessment. Credit measures were stable, anchored by the consistent earnings contributions from its utilities and power generation	Kenton Freitag

segments.

Hydro-Quebec (A+¶, A-1+¶ (¶Debt guaranteed by Province of Quebec (A+/Stable/A-1+)))

The long-term forecast on the company's financial profile is asset growth and financial stability, despite high capital expenditures in the next several years that could increase total debt by up to C$1 billion by 2010. Hydro-Québec has 1,055 MW of new hydroelectric generation assets under construction, which should come into service from 2006 to 2008. The company's strategic sale of its noncore foreign investments is essentially complete with the $1.5 billion sale of Transelec S.A. (BBB-/Stable/--) to Brookfield Asset Management Inc. (A-/Stable/A-2) that closed in third-quarter 2006. Funds from operations interest coverage improved marginally to 2.6x at year-end 2005, compared with 2.5x in 2004. Second-quarter 2006 (ended June 30) results were consistent with 2005 results, and Standard & Poor's Ratings Services' expectations. — Nicole Martin

Hydro One Inc. (A/Stable/A-1)

The ratings on Hydro One Inc. were affirmed on Sept. 15, 2006, and take into account the company's revised estimate of its level of annual capital expenditures. Subject to regulatory approval and project timing, capital spending by Hydro One will likely increase to between C$800 million and C$1.3 billion a year for several years, from close to C$700 million in 2005. Standard & Poor's Ratings Services expects the company to debt finance about 20% of its capital spending. The capital projects will, however, add to Hydro One's revenue-generating regulated rate base in the long term. In addition to financial pressure on the transmission and distribution utility's balance sheet, the potential for decreased profitability and weaker cash flow credit metrics as a result of the Ontario Energy Board's ongoing generic cost-of-capital review was also considered. A recent reopening of a transfer tax holiday for municipally held utilities could prompt some partnerships or asset swaps in the Ontario local distribution company sector. — Nicole Martin

TransAlta Corp. (BBB/Stable/--)

In the second- and third-quarter 2006, TransAlta Corp. management continued to focus on optimizing operational performance, managing merchant exposure in the North American electricity wholesale market, and shoring up the balance sheet for the company's expected next growth phase. Standard & Poor's continues to expect adjusted funds from operations (FFO) interest coverage of better than 4x and adjusted FFO to total debt coverage of more than 20% in 2006, and similar results in 2007. A decision regarding a potential joint venture with EPCOR Utilities Inc. (BBB+/Stable/--) to develop a greenfield coal-fired electricity generation asset in Alberta toward the end of this decade is expected later this year. Any change in the ratings will largely depend on TransAlta's ability to continue to strengthen its balance sheet in the remainder of 2006 and 2007, its ability to recontract merchant capacity at its Centralia plant at favorable market prices in 2008 and beyond, and the extent of any other material growth commitments during the same period. — Nicole Martin

Enbridge Inc. (A-/Stable/--)

Enbridge Inc.'s second-quarter 2006 (ended June 30) results were consistent with Standard & Poor's Ratings Services' expectations and continue to highlight the stability of its credit metrics, with funds from operations interest and debt coverages and leverage similar to those at year-end 2005. The company has material growth plans; it has identified at least C$8 billion in organic growth opportunities in the next five years. Accordingly, the ratings are increasingly focused on the company's ability to manage the project risk involved with its expansion, as well as maintaining a financial profile that is supportive of the current rating. — Kenton Freitag

TransCanada PipeLines Ltd. (A-/Negative/--)

TransCanada Pipelines Ltd.'s second-quarter 2006 results were modestly higher on a year-over-year basis. However, the operating segments demonstrated opposing trends. The pipeline segment showed declining earnings due to lower allowed ROE and a diminishing rate base on its Canadian Mainline and Alberta System pipelines. Improvements in the energy segment traced to higher volumes and improved margins in the power portfolio, as well as higher capacity and increased storage spreads in its natural gas storage facilities. — Kenton Freitag

Latin America

AES Gener S.A. (BBB-/Stable/--)

On April 20, 2006, Standard & Poor's Ratings Services upgraded AES Gener S.A. by one notch to 'BBB-' based on its better financial risk profile, demonstrated by its lower leverage, improving debt service coverage ratios, and favorable debt structure. AES Gener's profitability and cash flow benefited from the higher node prices in the Central Interconnected System (SIC) after the passage of the Short Law II in May 2005. In addition, AES Gener does not face significant refinancing risk in the next five years, as annual consolidated debt maturities are below $60 million until 2014, when bonds for about $570 million will become due. However, AES Gener remains exposed to natural gas supply shortages in Chile and to a drought in the SIC, because those factors affect the company's operating costs. A potential combination of both factors in the next two years would affect its financial performance. — Sergio Fuentes

Comision Federal De Electricidad (CFE) ((FC: BBB/Stable/--; LC: BBB+/Stable/--))

Lower oil and natural gas prices and new hydroelectric capacity are elements that were cited in Mexico's recent election as elements that could allow lower electricity rates become a reality. It is premature to assess the impact that this could have on Comision Federal De Electricidad's (CFE) credit profile. Nevertheless, it is relevant, given that a lack of a rate-setting policy that fully compensates CFE for all cost increases is viewed as a credit weakness. Other items that were highlighted by Mexico's president elect during the campaign included plans to develop schemes to allow large consumers to purchase electricity at more competitive costs, and allowing Mexico's energy companies to establish strategic alliances to have access to state-of-the-art technology. — José Coballasi

Companhia Energetica de Sao Paulo (CCC+/Positive/--)

Companhia Energética de São Paulo's (CESP) financial profile improved during 2006 after the BrR 1.2 billion capital injection by Sao Paulo and the BrR 2 billion primary share offering. However, the company's credit quality remains challenged by an aggressive debt amortization schedule and weak debt service coverage ratios. Standard & Poor's Ratings Services would revise the ratings upward, if CESP successfully extended its debt maturity profile and smoothed debt maturities in the next two years. — Juliana Gallo

Eletropaulo Metropolitana Eletricidade de Sao Paulo S.A. (BB-/Stable/--)

Eletropaulo Metropolitana Eletricidade de Sao Paulo S.A.'s rating was recently upgraded to 'BB-' due to the significant improvement of its financial risk profile, which benefits from the recent renegotiation of about 45% of its debt and from a debt reduction at the level of its holding company, Brasiliana Energia S.A (Brasiliana). Eletropaulo has recently extended the tenor of a BrR 2.7 billion debt with pension funds up to 2022. In addition, in September 2006, AES Transgas Empreendimentos S.A., which is majority owned by Brasiliana, sold a nonvoting stake in Eletropaulo for BrR1.17 billion through a public offering. Proceeds were used to repay debt at the level of Brasiliana. Those two factors resulted in a manageable debt amortization schedule through 2008 and lower pressure on Eletropaulo to upstream relatively high dividends to Brasiliana. — Marcelo Costa

Enersis S.A. (BBB-/Positive/--)

On a consolidated basis, Enersis S.A.'s lower debt levels, coupled with the favorable economic environment in Latin America and the passage of the Short Law II in Chile in May 2005, resulted in an improvement in consolidated funds from operations (FFO) interest coverage and FFO to average total debt to 3.8x and 27.7%, respectively, in the 12 months ended June 30, 2006. Individually, dividends and interest payments from its 98%-owned subsidiary Chilectra S.A., allow Enersis to cover its interest expenses. In addition, Standard & Poor's Ratings Services expects dividends from its 60%-owned Empresa Nacional de Electricidad S.A. to continue increasing, based on its improving profitability and cash flow generation. — Sergio Fuentes

Interconexion Electrica S.A. E.S.P. (ISA) (Foreign currency: BB/Positive; Local currency: BBB-/Stable)

The ratings on Interconexion Electrica S.A. E.S.P. (ISA) reflect the company's dominant position in Colombia's power transmission system, its natural monopoly, the government's ownership, and its strategic importance for the Republic of Colombia. On Nov. 14, 2006, Standard & Poor's Ratings Services lowered the local currency corporate credit rating on ISA to 'BBB-' from 'BBB' and removed it from CreditWatch with negative implications, where it was placed on June 20, 2006, following the company's acquisition of a 50.1% controlling stake in Companhia de Transmissão de Energia Paulista. The downgrade reflected an aggressive financial policy evidenced by continued debt-funded acquisitions. The rating action took into consideration ISA's expected deleveraging of its capital structure through a stock issue in 2007, as well as the expected associated improvement in the company's financial measures. — Fabiola Ortiz

U.S.

American Electric Power Co. Inc. (BBB/Stable/A-2)

American Electric Power Co. Inc. (AEP) faces an almost constant cycle of regulatory proceedings in one or more of the 11 states in which it operates, as well as at the federal level. The Texas Public Utilities Commission's decision to cut stranded-cost recovery was a credit disappointment. The mostly coal-burning company will be spending a lot of money on environmental compliance, a massive undertaking that heightens operating risk and regulatory risk, and threatens AEP's generation cost advantage. — Todd Shipman

Consolidated Edison Inc. (A/Negative/A-2)

Consolidated Edison Inc. announced a reduction in earnings guidance for 2006 after its 10-day power outage in Queens and smaller, sporadic interruptions in other parts of its New York City service territory. The new earnings target and reduced cash flow, associated with emergency response, permanent repairs, customer claims, and potential penalties, will further depress the company's already-weak financial measures. As of June 30, 2006, funds from operations (FFO) to total debt was about 13%, FFO interest coverage was 3.1x, and debt to capital was 55%. The current ratings factor in the expectation that regulatory rate increases, such as subsidiary Consolidated Edison Co. of New York's rate increase of $220 million in 2007, will continue. — Kenneth L. Farer

Constellation Energy Group Inc. (BBB+/Negative/A-2)

A new state law requires subsidiary Baltimore Gas & Electric Co. to defer recovery of power costs, but also allows immediate relief through securitization. A troubling precedent of legislative intervention could still affect the utility's credit quality, if future supply cost increases are also controlled. Repricing of Constellation Energy Group Inc.'s power generation fleet is expected to increase cash flow on a consolidated basis. Consolidated financial measures are weak in 2006 after adjusting for debt like obligations, but the use of proceeds from the proposed sale of 3,800 MW of gas-fired assets for debt reduction will benefit balance-sheet strength. — Aneesh Prabhu

Dominion Resources Inc. (BBB/Positive/A-2)

Lower gas prices and mild weather have mitigated fuel-related expenses, which are unrecoverable above a frozen fuel factor through mid-2007. A strategic review undertaken by the company has resulted in a decision to sell most of the Dominion Resources Inc.'s exploration and production (E&P) assets, especially since changes in Virginia legislation obviate the need for E&P to act as a natural hedge for utility fuel costs. Proceeds from the sale will be first used to achieve targeted financial measures, which Standard & Poor's Ratings Services views as credit supportive. The sale would also support an overall lower business risk. Liquidity concerns have receded with gas prices at a more sustainable — Aneesh Prabhu

level.

Duke Energy Corp. (BBB/Positive/NR)

Duke Energy Corp.'s plans to separate the electric and natural gas operations are proceeding on schedule, with a start date of Jan. 1, 2007. Standard & Poor's Ratings Services reviewed the company's proposal and revised the outlook on Duke Capital Corp. (in essence the core of the new gas company) to positive, to reflect that entity's potential for a ratings upgrade of up to two notches. At the same time, the ratings on the remaining electric company were affirmed with a positive outlook, to reflect the likelihood for a higher rating as well. Duke Energy has followed through with its plan to reduce and mitigate business risk at the regulated operations, most recently completing the sale of Cinergy Corp.'s trading and marketing operations to Fortis NV of the Netherlands. — Dimitri Nikas

Edison International (BBB-/Stable/NR)

Ratings stability is expected in the near term, following a recent rating downgrade in response to revised strategic policies that allow capital infusions to be made into unregulated subsidiaries, if needed to support growth initiatives, and if they are in the shareholders' best interest. The company exhibited steady to gradual improvement in fully adjusted funds from operations (FFO) interest coverage of about 2.9x and in FFO to total debt of about 15% as of June 30, 2006. — David Bodek

Entergy Corp. (BBB/Negative/--)

Entergy Corp.'s pursuit to recover hurricane-related costs in its service territories, incurred in 2005, is ongoing. The company has made some progress through the implementation of securitization bills in Texas and Louisiana, but the timing of the recovery and amounts remain uncertain. Entergy estimates storm damage of $700 million in Louisiana and $390 million in Texas. The bankrupt subsidiary Entergy New Orleans recently filed its reorganization plan that is currently being debated among the various creditor classes, and the company could emerge from bankruptcy by year-end 2007 if the parties agree. At the same time, Entergy New Orleans has received an allocation of about $200 million in federal grant money that will undoubtedly help. The consolidated business risk profile continues to reflect some pressure from ongoing regulatory challenges, such as in Arkansas, as well as the company's increasing involvement in nonregulated generation, such as the recent purchase of the Palisades nuclear plant from Consumers Energy Co. Nevertheless, the consolidated financial profile remains robust, with adequate credit-protection measures for the 12-months ended Sept. 30, 2006. — Dimitri Nikas

Exelon Corp. (BBB+/Watch Neg/A-2)

On Oct. 5, 2006, Standard & Poor's lowered its corporate credit rating on Commonwealth Edison (ComEd) to 'BBB-' from 'BBB+'. The rating remains on CreditWatch with negative implications. At the same time, Standard & Poor's placed its 'BBB+' corporate credit ratings on Exelon Corp., Exelon Generation Co., and PECO Energy Co. on CreditWatch with negative implications. The ratings actions reflect the increased potential for legislators in Illinois to extend ComEd's current rate freeze for another three years. The Illinois House of Representative could vote on rate freeze legislation by the end of November. ComEd has indicated that it will lose about $4 million per day (pretax) if the rate freeze is extended. Despite having taken various steps to insulate itself from a bankruptcy filing at ComEd, if rate freeze legislation is signed into law, the overall credit quality of Exelon and ExGen would decline due to heightened counterparty credit risk at ExGen (ComEd and Ameren Corp.'s utilities will be customers of ExGen after 2006) and the potentially permanent loss of dividend income from ComEd to Exelon. — Jeanny Silva

FirstEnergy Corp. (BBB/Stable/--)

The company's rate certainty plan in Ohio will lower cash flow in the near term, but is viewed as credit neutral, as it preserves the recovery of increased fuel costs after 2008. The company's operating performance has been satisfactory, but doubts remain on the sustainability of nuclear operations. Rate cases in Pennsylvania and the post-2008 market structure in Ohio are other risks. Climbing maintenance expenditures will cut into free cash flow in 2006. Financial metrics and liquidity have improved markedly, as substantial debt was paid down in 2005. A share-repurchase program will bruise credit metrics, but they will remain consistent with ratings. — Todd Shipman

FPL Group Inc. (A/Stable/--)

FPL Group Inc.'s consolidated financial performance for the 12 months ended June 30, 2006 was below expectation, driven by the lingering cash flow effect of the 2004-2005 hurricanes and underrecovered fuel costs at the utility. The CreditWatch with negative implications listing reflects the announced merger with Constellation Energy Group Inc. The combined entity would likely have a higher business risk profile and weaker financial risk profile, because it would have a significantly higher percentage of cash flow from higher-risk competitive businesses, with little change in the pro forma balance sheet. — Jodi Hecht

Pacific Gas & Electric Co. (BBB/Stable/A-2)

Long-term electricity and fuel-procurement activities are ongoing and will define the utility's operational and financial profile. The California Public Utilities Commission remains committed to providing relief in response to material changes in utility costs, which contributes to rating stability. The company exhibited gradual improvements in cash flow coverage measures as of June 30, 2006, with fully adjusted funds from operations (FFO) to interest coverage of 3.4x and FFO to total debt of about 18%. — David Bodek

Progress Energy Inc. (BBB/Positive/A-2)

Financial performance for the 12 months ending June 30, 2006 improved slightly, as the fuel surcharge for Progress Energy Florida and Progress Energy Carolinas continue. Adjusted funds from operations to average debt improved to 15% compared to 14% in the previous year. The short-term focus remains on the execution of the debt-reduction plan, as — Jodi Hecht

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the company exits higher-risk businesses.

Public Service Enterprise Group Inc. (BBB/Negative/A-3)

Meaningful debt reduction is contemplated, with the cash distributions from PSEG Energy Holdings LLC after the termination of merger proceedings with Exelon Corp. Cash flow over the next six months will benefit from revenue enhancements associated with the New Jersey Board of Public Utilities' most recent wholesale electricity auction, and from operational improvements. Both electric and gas rate cases were delayed due to merger proceedings, but are expected to be filed soon. — Aneesh Prabhu

Sempra Energy (BBB+/Stable/A-2)

Consistent and predictable financial performance is expected at the utilities and Sempra Generation. Significant upcoming capital expenditures at the utilities, liquid natural gas (LNG) projects, the Rockies Express pipeline, and perhaps additional nonregulated assets could limit the amount of debt that can be paid down. Under conservative assumptions for Sempra Commodities, ratios are expected to be weak for the rating in 2006 and 2007, with funds from operations interest coverage and debt somewhat lower than 4x and 23%, respectively. This is because Sempra invested substantial sums in its LNG and pipelines businesses without any cash flows. For the 12-months ended June 30, 2006, these ratios stood at 4.1x and 22.8%, respectively. Ratios will improve significantly from 2008 onward, even under conservative assumptions for Sempra Commodities. — Swami Venkataraman

Southern Co. (A/Stable/A-1)

Retail kilowatt sales were up 2.5% for the first half of 2006, compared with first-half 2005, mostly from customer growth and weather-related factors. Customer growth was 1.3% for the year ended June 2006. Mississippi Power Co. continues to evaluate several options to recover the costs to repair Hurricane Katrina damage, and federal grants could form part of the funding package. Adjusted funds from operations interest coverage was 4.8x for the year ended June 30, 2006, and should be around 5x through 2008. — Terry Pratt

TXU Corp. (BBB-/Negative/NR)

The negative outlook continues to reflect the potential for a lower rating, once the financial effects of TXU Corp.'s planned $10 billion program to build 11 coal-fired power plants is factored into the consolidated rating. Retail customer counts continue to decline. For the 12 months ended June 30, 2006, adjusted funds from operations (FFO) to interest coverage was 5.1x and adjusted FFO to average total debt was 27.4%. However, leverage remains high compared with peers, as measured by an average total debt to total capital ratio of about 96%. — Terry Pratt

Europe

Edison SpA (BBB+/Stable/A-2)

Over the first half of 2006, Edison SpA's EBITDA was robust, at €774 million, due to strong volume growth and effective portfolio management in the electricity division, as well as improving procurement terms of gas purchases and higher selling prices of equity gas in the gas division. Consolidated net debt stood at about €4.8 billion, a slight decline from December 2005. — Monica Mariani

Electricite de France S.A. (AA-/Negative/A-1+)

Electricite de France S.A's (EDF) satisfactory operating performance in the first half of 2006, with organic EBITDA growth of 3.3%, was driven primarily by international operations, which posted organic EBITDA growth of 6.1%, while the French operations only recorded a 1.5% rise. The French operations were affected by increased input costs, unfavorable weather and hydro conditions, and reduced availability of the nuclear plants in the first quarter, but benefited from cost savings. EDF will benefit in the second half of 2006 from the recently approved 1.7% increase in regulated supply tariffs. The international operations benefited in the first half of 2006 from the increased contribution of German affiliate EnBW and of EDF Trading. The group reduced its financial debt in the first half of 2006 -- despite a €1.3 billion payment for nuclear decommissioning and a €1.4 billion outflow for dividends -- due to its strong operating free cash flow of €4.1 billion, which was boosted by lower-than-expected capital expenditures, and €0.9 billion of disposals. EDF is now aiming for its reported financial debt to be lower at the end of 2006 than at the end of 2005. — Hugues de La Presle

Endesa S.A. (A/Watch Neg/A-1)

The ratings on Endesa S.A. remain on CreditWatch with negative implications, following German energy utility E.ON AG's announcement on Sept. 26, 2006, of an increase in its bid for the Spanish utility. The operating performance of Endesa in the first half of 2006 was stronger than anticipated, with EBITDA growing 33% to €3.7 billion. This is the result of all the geographical business areas (Iberia, Latin America, and Europe) experiencing EBITDA growth between 30% and 38%. Driven by these excellent results, the company's management decided to revise upward the 2005 to 2009 strategic plan growth commitments given to the market in October 2005. EBITDA is now expected to grow by 38% from 2005 to 2009, and the dividend payout commitment is increasing accordingly. Net debt showed a slight increase of 4%, to €19 billion, from €18.2 billion at December 2005, mainly driven by the group's capital expenditures (€1.5 billion) and the financing of the tariff deficit that the Spanish system experienced again in the first half of the year (€572 million). Credit metrics strengthened, however, due to increased profitability and cash flow generation. Based on unaudited numbers, annualized funds from operations (FFO) to debt was 25% and FFO to net interest was 5.7x. The negative CreditWatch implications on Endesa reflect Standard & Poor's Ratings Services' initial assessment of the risk, albeit limited, of a deterioration in Endesa's profile to a level commensurate with an 'A-' rating, if any of the bids are successful. This initial assessment did not, however, anticipate the €1 billion bank guarantee posted in relation to a mercantile court suspension, or the recent, temporary changes to the Spanish wholesale power market regime (resulting from the Royal Law Decree 3/2006) and the resulting potential negative effects on Endesa's profitability. — Ana Nogales

Enel SpA (A+/Negative/A-1)

Monica Mariani

Over the first half of 2006, Enel SpA reported satisfactory results, with recurring EBITDA at €4 billion, growing by 5.3% primarily as a result of international activities and grid operations. Reported net debt grew to €14.1 billion from €12.3 billion at year-end 2005, reflecting primarily the effect of the consolidation of Slovenske Elektrarne and of €2.7 billion of dividends paid in June 2006. An additional €1.2 billion in dividends will be paid in November, as an interim dividend on 2006 results. Enel's international activity remains dynamic and resulted in the completion or announcement of several acquisitions in Eastern Europe and Latin America, the most notable Slovak generator Slovenske Elektrarne and Romanian distribution company Muntenia Sud. The group will continue to seek acquisition opportunities over the coming months. Barring material acquisitions, Enel should be able to maintain a ratio of funds from operations to adjusted total debt of about 30% in the short term. Over the longer term, Standard & Poor's Ratings Services expects Enel's financial profile to deteriorate from its current strong level, as the company releverages its balance sheet through capital expenditures, dividends, and acquisitions.

Energias de Portugal (A/Stable/A-1)

Ana Nogales

The strategic plan announced recently by Energias de Portugal S.A.'s (EDP) new management entails €5.6 billion of capital expenditures between 2006 and 2008, of which €2.1 billion on renewable energy and €1.4 billion to boost the group's generation capacity. Such investments are expected to be partially funded by about €800 million of sales. The group has also committed to increase its dividend by 8% per year on the back of an annual 11% growth in EBITDA over the period. Despite its substantial investment program and the planned increase in its dividend, EDP aims to improve its financial profile by 2008, its objective to reduce debt to EBITDA as calculated by the company to 3.8x in 2008 from 4.6x in 2005. EDP needs to improve its financial profile, which is currently weak for the ratings.

EnBW Energie Baden-Wuerttemberg AG (A-/Positive/A-2)

Amrit Gescher

EnBW Energie Baden-Wuerttemberg AG's (EnBW) debt increased slightly in the first half of 2006, despite satisfactory operating performance, due to a strong receivables-related increase in working capital, the payment of dividends and, above all, consolidation of Stadtwerke Duesseldorf. The company is expecting further operating improvements (albeit tempered by the onset of regulation on its German network operations) and a continuation of its consolidation in the short term, although its appetite for generation and strategic investments has also increased. The positive outlook reflects the potential for ratings improvement over the medium term, if EnBW can further improve its financial profile and establish a track record of sustained financial improvement, as it shifts its focus from consolidation to growth. Nevertheless, any deterioration of its business position from increased regulation and competition in the German electricity and gas markets, together with growing investments, could temper the scope for ratings improvement.

E.ON AG (AA-/Watch Neg/A-1+)

Amrit Gescher

E.ON AG posted a robust performance for the first half of 2006, although its net cash position at year-end 2005 turned to a moderate net financial debt position of €2.6 billion, partially owing to the payment of a special dividend related to the disposal of E.ON's 43% Degussa stake and payments for a contractual trust arrangement for pension commitments (which were previously on the balance sheet). The rating was placed on CreditWatch with negative implications on Feb. 21, 2006, following the company's announcement of its intended all-cash offer for up to 100% of Endesa for €25.4 per share (after the payout of a special dividend by Endesa). On Sept. 26, 2006, E.ON said it would increase its offer to €35 per share. Following the bid, the Spanish government passed provisional regulations affecting the Spanish wholesale power market. These regulations could reduce the profitability of the vertically integrated Spanish utilities and, if the situation is prolonged, it could have incremental negative ratings implications. A recent German court ruling shortening the duration of E.ON's wholesale gas contracts, network tariff cuts by Germany's new energy regulator, and a fairly challenging market environment in the U.K. also imply a moderate increase in E.ON's business risk. E.ON has stated that it will defend its objective of maintaining an 'A' rating with a capital increase of up to 10% of total share capital, if necessary. Standard & Poor's Ratings Services also notes the group's wide asset base and the potential for disposals, if necessary. Given the perceived incremental weakening of E.ON's business position, we now expect that a ratio of funds from operations to adjusted net debt of more than 20% would be required to maintain an 'A'-category long-term corporate credit rating (compared with our previous expectation of 20%).

Iberdrola S.A. (A+/Watch Neg/A-1)

Ana Nogales

The ratings were placed on CreditWatch with negative implications on Sept. 6, 2005, following Gas Natural SDG, S.A.'s (A+/Watch Neg/A-1) €22.55 billion bid for a 100% stake in Endesa and its agreement to a subsequent sale of an estimated €7 billion-€9 billion in assets to Iberdrola. In the first half of 2006, Iberdrola's operating performance remained strong, with EBITDA growing 20% to €1.9 billion, from €1.6 billion in the same period of 2005. This growth was driven by the wind power and international operations. This EBITDA figure includes, however, €353 million of tariff deficit. The group's financial profile remains weak, with net debt increasing by 11% to €13.6 billion, driven by the need to finance the tariff deficit and the continuing expansion strategy in international renewable operations. In addition, Iberdrola's involvement in Gas Natural's bid for Endesa indicates that the company is ready to pursue an aggressive acquisition strategy.

National Grid PLC (A/Watch Neg/A-1)

Paul Lund

The ratings on National Grid PLC were placed on CreditWatch with negative implications on Feb. 24, 2006, after news of the potential acquisition of KeySpan Corp. (A/Watch Neg/A-1), a diversified energy company based in the northeast U.S. National Grid will pay £4.2 billion for KeySpan's equity, to be raised entirely in additional borrowing. This is in addition to the assumption of about £2.5 billion of existing debt at KeySpan. As of Sept. 1, 2006, National Grid had already raised £3.3 billion of its £6 billion funding target. The acquisition debt is all expected to be raised at the group holding company level. The acquisition is set to be completed during first-quarter 2007. Standard & Poor's Ratings Services expects to resolve the CreditWatch status once the acquisition becomes unconditional, following approval by the New York Public

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Service Commission. Any lowering of the rating is likely to be limited to one notch.

RWE AG (A+/Negative/A-1)

RWE AG's core operating performance continued its robust path in the first half of 2006 and net debt declined from year-end 2005, despite the outflow of the full-year 2005 dividend. The company's ongoing sale of the bulk of its water business, which was announced in November 2005, accounting for about one-quarter of the group's operating earnings, and the likelihood that it will invest some of these proceeds into riskier energy operations, is likely to weaken the company's very strong business profile and could have negative implications, if followed by rapid and extensive use of its financial flexibility. This could occur if investments are made in riskier operations or markets. RWE's clearly defined dividend policy, strong track record of financial consolidation in recent years, and strict acquisition criteria moderate the likelihood of such a development. Nevertheless, RWE could be subject to the M&A-related event risk currently characterizing Europe's consolidating energy markets. For the ratings to be maintained, the group will need to restrict itself to moderate-scale or low-risk acquisitions, as well as maintaining conservative financial policies. On Oct. 16, 2006, RWE announced its intention to sell U.K.-based water subsidiary Thames Water Holdings PLC for £4.8 billion (the transaction will likely be concluded in late 2006). The sale of RWE's U.S. water business should be completed in 2007. Proceeds from the sale of the U.K. and U.S. water assets will likely result in a net cash position by year-end 2006, which would increase further in 2007 before any acquisitions. Based on a lowered net-debt ceiling of €10 billion to €12 billion after the disposals, however, RWE expects to have headroom for acquisitions, if opportunities arise.

Amrit Gescher

Scottish Power U.K. PLC (A-/Stable/A-2)

Scottish Power U.K. PLC's agreement to sell its U.S. subsidiary PacifiCorp and return £2.25 billion of capital to shareholders is consistent with Standard & Poor's Ratings Services' expectations, and is already factored into ratings. Scottish Power concluded the disposal, ahead of our expectations, for a consideration of $5.1 billion in cash and the assumption of $4.3 billion in net debt and preferred stock. The financial impact of the PacifiCorp sale is likely to be positive, given a marked reduction in Scottish Power's debt, PacifiCorp's worse-than-expected recent performance, and the sharp reduction in capital-expenditure requirements. Nevertheless, we expect Scottish Power to pursue investments in higher-risk, competitive activities, which may gradually increase business risk. Scottish Power produced a strong financial performance for the year ended March 31, 2006, as operating profit was up 39%, with all businesses contributing to the growth. From July 10, 2006, the company's electricity prices will rise by an average 10%, while gas prices will increase by an average 17% as a result of rising wholesale prices.

William Ferara

Suez S.A. (A-/Watch Pos/A-2)

Suez S.A. continued to perform strongly in the first half of 2006, with organic sales growth of 9.5% and EBIT up 13.9%, thanks to strong contributions from all of the group's four businesses. As a result, management has reviewed upward its guidance for the year, now expecting sales to grow by more than 7% and EBIT to rise by more than 15%. The group is also aiming for reported net debt to be below €12 billion at the end of 2006. Reported net debt stood at €13 billion at the end of June 2006, but has declined since then, due to the €1.2 billion proceeds Suez has received for the disposal of some of its stakes in the Belgian intermunicipal distribution companies. Suez and Gaz de France S.A. appear to have made some progress toward their merger.

Hugues De La Presle

Vattenfall AB (A-/Stable/A-2)

The recent revision of Vattenfall AB's outlook to stable from positive reflects the increasing regulatory and political pressure in the group's main markets of Sweden and Germany. Over the past year, several adverse regulatory and fiscal actions have affected Vattenfall. In Sweden, taxation on power generation has increased and electricity network distribution regulations have also become stricter. In 2006, the German network regulator imposed a decrease in transmission tariffs by almost 18%. Additional adverse measures cannot be ruled out. As a fully state-owned utility, Vattenfall could also become subject to political actions, such as potential restructuring of the company, major changes in strategy, or potential privatization. Financial performance during the first half of 2006 remained strong, mainly as a result of very high wholesale power prices in the Nordic region and in Germany.

Andreas Zsiga

Veolia Environnement S.A. (BBB+/Stable/A-2)

Veolia Environnement S.A.'s operating performance has remained strong in 2006, with organic sales growth of 9.9% in the first half. As a result, the group is now targeting a growth in sales of more than 10%, with a faster growth in its EBIT. The group's financial profile remains moderate, however. In addition, Veolia's strategy, which Standard & Poor's Ratings Services assumed rested primarily on organic growth, complemented only by add-on acquisitions, is somewhat blurred following its interest in French concession and construction group VINCI S.A., and the international environment assets of Suez S.A.

Hugues De La Presle

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Table 2

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Comments and ratings reflect available public data as of Nov. 21, 2006.

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Pipelines And Utilities

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December 3, 2001

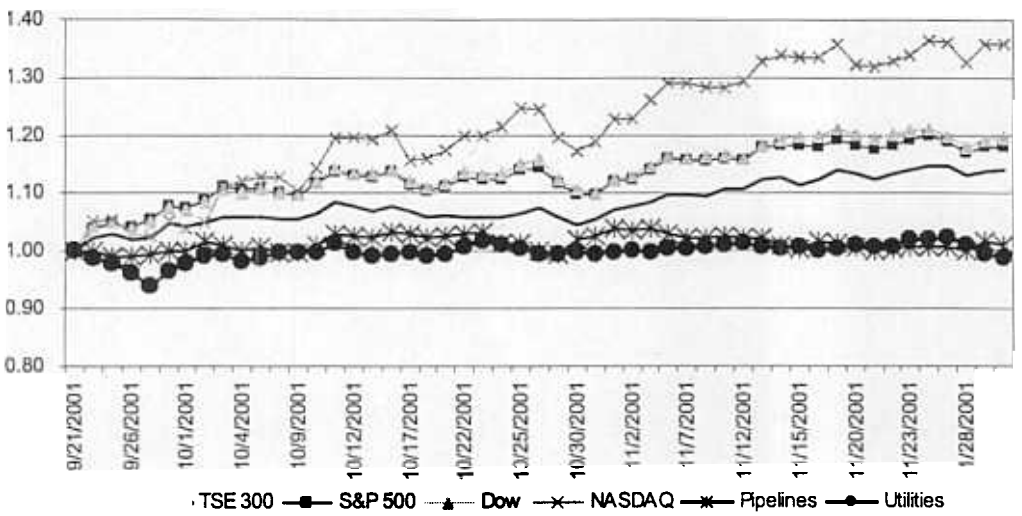
Time To Lighten Up

All figures in Canadian dollars, unless otherwise stated.

Investment Conclusion

- The recent broad market rally from September 21 lows likely signals the start of a new bull market phase and as such has significant implications for pipeline and utility stocks. In the near term, we expect a consolidation of recent market gains during which pipeline and utility stocks may outperform again; however, we would use this as an opportunity to trim exposure to the group. We would focus remaining exposure on those companies with the best potential earnings growth and, in particular, those that effectively use performance-based regulation and strategic acquisitions and increase the proportion of nonregulated assets and operations in their business mix.

Figure 1. Sector Performance Relative To Broader Indices



Prices as of market close November 30, 2001.
Source: Starquote.

- November saw the markets rally and the start of a rotation into more cyclical stocks. As a result, the pipelines and utilities underperformed the TSE in November; while the TSE 300's total return was 8.0%, that of the utilities was virtually zero, and the pipelines was negative 1.3%. Contributing to the underperformance was the back-up in long Canada bond yields, which have risen by approximately 40 basis points from recent lows. Pipeline and utility stocks are highly *negatively* correlated with long Canada bond yields. Figure 1 shows the relative performance of the sector to broader indices from the September 21 low, and figures 2 and 3 show individual company performance in November and year-to-date. The sector underperformed in the month, even after accounting for the dividend yield, as shown in Figure 4.

See page 2 for state/provincial restrictions.

- The shock of the failure of Enron and the uncertainty about any possible domino effect has put pressure on the stock prices of energy merchants and may continue to overhang the sector, and potentially the broader market, until the situation is clearer. We note, however, that all of the companies in our universe have indicated that they do not have any direct material exposure to Enron. We expect that other marketers should be able to step in and fill the gap left if EnronOnline were to be permanently turned off, although we are less certain of the duration and magnitude of any reduced liquidity and resultant increased volatility in the power and gas markets.

- Over the next 12 months, as an economic recovery unfolds, there will likely be upward pressure on short- and long-term interest rates. At the same time, a recovery will continue to diminish the defensive appeal of these stocks and highlight the better relative growth prospects of more cyclical or economically sensitive sectors. As well, we continue to have valuation concerns about the distribution utilities, which are trading at about a 2.1-multiple-point premium and a 90-basis-point yield discount compared to U.S. comparables with similar growth rates and risk profiles (see Table 1).

Table 1. Canadian Valuation Premium

	2002 P/E	Dividend Yield
Canadian Gas & Electric Utilities	13.9	4.4%
U.S. Gas & Electric Utilities	11.8	5.3%

Source: CIBC World Markets.

- **TransAlta** (TA – Buy) A recession will reduce industrial power demand, which will likely prolong recent weakness in electricity prices; however, with most of TA's output contracted long term and at fixed prices, our recommendation has been premised on expectations of growth in TA's generation portfolio and the enhanced returns achievable from its Alberta generation assets in a deregulated environment. With its dividends providing about a 4.3% yield, the stock now offers excellent income and downside protection while preserving the longer-term upside. In the mean time, the weaker balance sheets of some of its competitors may facilitate acquisition opportunities.

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Emera: Solicitation only allowed in DC, GA, LA, NY, PA.

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TransAlta Corp.: Solicitation prohibited in AL, IL, KY, NH, ND, SD, UT, VT, VA, WI.

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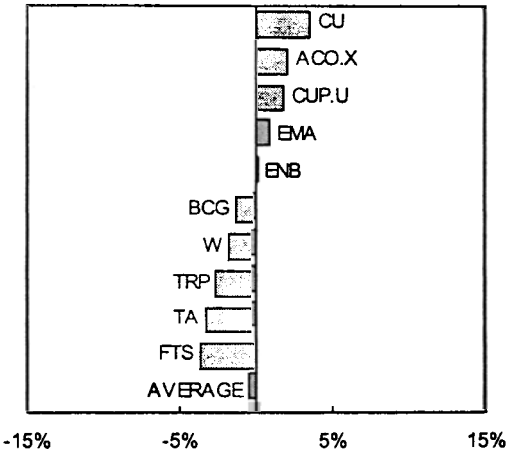
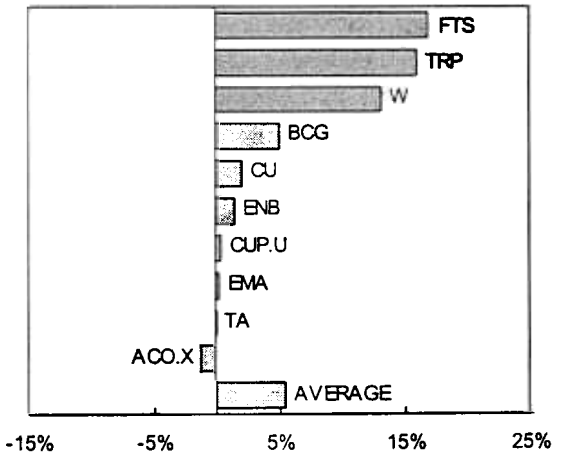
- **Enbridge** (ENB – Buy) has demonstrated the strongest and most consistent EPS growth of the sector. It is benefiting from incentive regulation at Consumers Gas, from the recently completed Midcoast Energy acquisition, and from rising oil production in Western Canada, which will boost demand for its oil pipeline. Confidence in the latter outcome is heightened by customers' recent requests that Enbridge proceed with the third phase of the Terrace expansion. We believe that the recent purchase of 25% of the Spanish energy transportation company (CLH) indicates the increasing contribution and strength of Enbridge's international operations.

Figure 2. Monthly Stock Price Performance



Prices as of market close November 30, 2001.
Source: Starquote.

Figure 3. Year-To-Date Stock Price Performance



Prices as of market close November 30, 2001
Source: Starquote.

Figure 4. Total Return Of Pipelines And Utilities

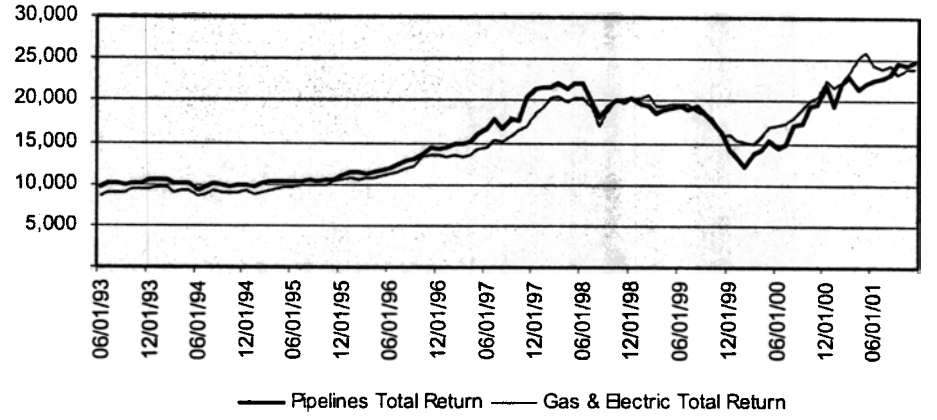


Chart data up to November 30, 2001.
Source: Bloomberg.

Figure 5. Pipeline And Utility Yields Relative To 10-Year Government Bond Yield

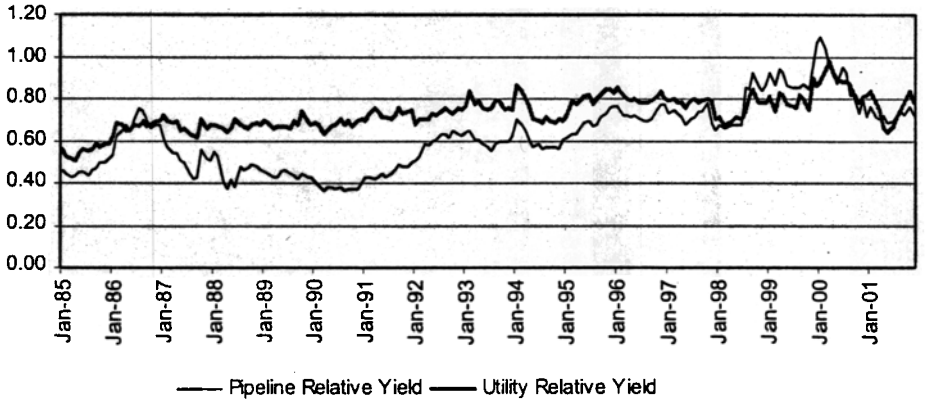


Chart data up to November 30, 2001.
Source: Bloomberg, CIBC World Markets.

Multi-Pipeline ROE Determined

The return on equity (ROE) adjustment mechanism approved in the National Energy Board's (NEB) multi-pipeline (MPP) cost-of-capital decision can now be calculated, as the November Consensus Forecast of government bond yields has been published. Based on our calculation shown in Table 2, the MPP ROE should be 9.53% for 2002 versus 9.61% in 2001. Last month we estimated the ROE to be 9.65%, but anticipated that the forecasted bond yields would fall; we have therefore already incorporated a lower ROE into our company valuation models.

Table 2. National Energy Board ROE

	November Calculation	Our High-End Estimate Last Month
Feb 2002 Gov't. 10-yr. Bond	4.90	5.10
Nov 2002 Gov't. 10-yr. Bond	5.40	5.50
Avg. 2002 Gov't. 10-yr. Consensus	5.15	5.30
Spread – 30-yr. and 10-yr. Can. Gov't. Bonds	0.48	0.48
Forecast 2002 30-yr. Bond	5.63	5.78
Forecast 2001 30-yr. Bond	5.73	5.73
Difference X 0.75	(0.08)	0.04
2001 Approved ROE	9.61	9.61
2002 Approved ROE	***9.53%***	***9.65%***

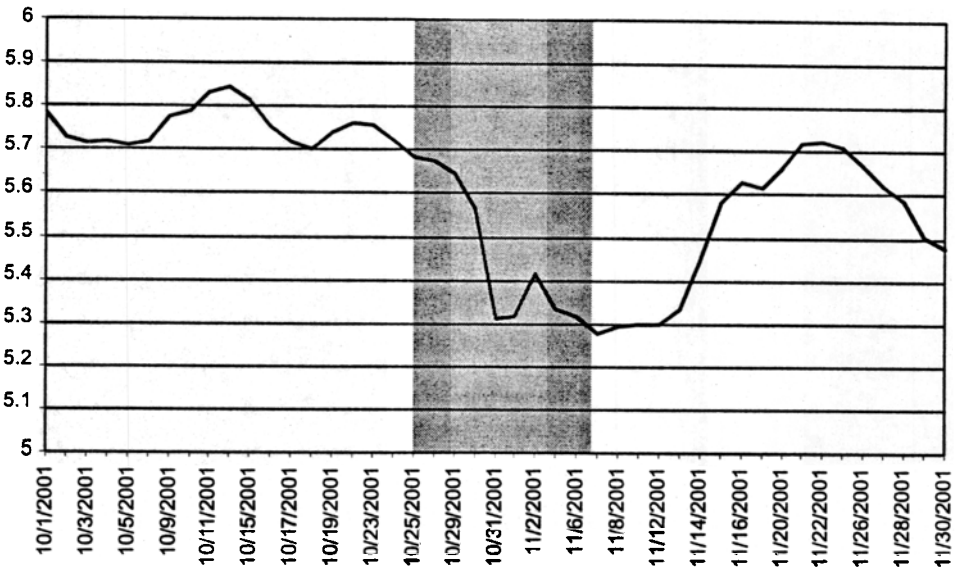
Source: Bloomberg, Consensus Economics, NEB, CIBC World Markets.

On November 9, we reduced our earnings estimates for Fortis after the Newfoundland Board of Public Utility Commissioners reduced the allowed return on equity for Newfoundland Power to 9.05% — the lowest return awarded to any Canadian utility. This return was based on a snapshot bond-yield formulaic approach to determining rates (as opposed to the NEB's consensus forecast approach). The snapshot was of Canada bond yields in the last five days of October and the first five days of November, and this time period is shaded in Figure 6.

The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

In our view, the return produced by the Newfoundland Board of Public Utility Commissioners and that produced by the NEB formula, increases the significance of applications by TransCanada PipeLines to the NEB and by Consumers Gas to the Ontario Energy Board (OEB) for an increase in allowed returns. It will be important for investors to watch these proceedings closely.

Figure 6. Long Canada Government Bond Yields



Source: Bloomberg.

Sector's Direct Exposure To Enron Very Limited

We are not changing our earnings estimates, target prices, or ratings, for companies in our universe as a result of their counterparty exposure to Enron. Last month we noted that companies in our universe had reassured us that they did not have any material exposure to Enron, and more recently, companies have once again reassured us that the direct exposure is immaterial (we estimate less than 1% of revenues); however, there is lingering uncertainty about the possibility of a domino effect in the energy trading markets. We expect that other marketers should be able to step in and fill the gap if EnronOnline were to be permanently turned off, although we are less certain about the duration and magnitude of any reduced liquidity and resultant increased volatility in the power and gas markets.

Companies trading in EnronOnline are typically subject to a "master agreement" that provides for netting out of the contracts, and Table 3 summarizes approximate net positions. Enron bought the future output of one of TransAlta's generating plants (in a contract worth approximately $294 million), but this contract is guaranteed by the Alberta provincial balancing pool. Enron also has contracted for firm capacity on TransCanada's pipelines, but the company believes that if one shipper were to default, that this would be absorbed by the other system's shippers and not the company's shareholders.

Table 3. Summary Of Exposure To Enron

Company	Net Position	Disclosure of Net Impact	Est. % Revenue
Enbridge Inc.	Payable to Enron	approximately $9 mln. USD (through Midcoast acquisition)	0.31%
TransAlta	Neutral	payable and receivable of US$10 mln. nets out	0.02%
TransCanada PipeLines	NA	"not material" – company declined to define "material"	NA

Source: Companies, CIBC World Markets.

We believe that the competition will attempt to step in and fill the gap Enron is sure to leave. An industry publication on November 30 suggested that JP Morgan Chase and Citibank were in serious talks on November 29 to take over all or part of Enron's multi-hundred-billion-dollar notional book of trading positions. It is expected that the banks would primarily warehouse existing contracts as they wind down over the next decade or so, but could potentially continue over-the-counter (OTC) commodities derivatives trading at a lower level. Creditors with recourse to nontrading assets, however, would perhaps contest the potential bailout. We note that other trading platforms such as Intercontinental Exchange (ICE), while stretched in the shorter term, could step in to provide liquidity.

Recent Sector Activity

Enbridge Expands Into Europe

On November 26, Enbridge announced that it had signed a letter of intent to purchase 25% of the common shares of Spanish transportation company Compañía Logistica de Hidrocarburos CLH, S.A. (CLH) for approximately C$530 million. That same day, we published our favourable views on the transaction, namely that it would be immediately accretive to earnings, that it was in line with both the corporate and international strategies, and that it created options for future partnerships with large integrated oil companies. We increased our 2002 and 2003 EPS estimates slightly, and retained our target price of $50 and our Buy rating.

Companies Sign On To Alaska Highway Pipeline

On November 15, six U.S. and three Canadian companies announced the signing of a memorandum of understanding to develop a proposal for the Alaska Highway pipeline, which they expect to put before Alaska North Slope producers by year end. The Canadian companies are TransCanada, Westcoast, and Foothills.

This has not changed our investment outlook for companies in our universe, as we note that the producers, not the pipeline companies, will drive the decision as to which route and which partners make most economic sense for Northern Gas. Furthermore, gas delivery is not expected before 2008. We also note that the large number of proposed LNG projects could provide 7 Bcf/day to 8 Bcf/day of supply by 2010 and keep gas prices in the range of US$3.00/Mcf to US$3.50/Mcf. At this price, it will be difficult for Alaska gas to compete via the highway route. For example, Enbridge estimates the transportation cost alone of the highway route at US$2.39/Mcf and the over-the-top route at US$2.07/Mcf.

TransCanada Mainline Tolls And Tarriffs Approved

As expected, the NEB has approved TransCanada's 2001 and 2002 Mainline tolls and tariff application, which was based on an agreement supported by the bulk of TransCanada's customers. The agreement fixes most of the elements of TransCanada's Mainline revenue for 2001 and 2002, and retains TransCanada's immunity from volume fluctuations. Yet to be decided is the cost of capital that TransCanada will be allowed to recover in each year. This will be the subject of a hearing that will begin in February. We are maintaining our $21.00 target price and Hold rating.

Milestone Completed In Duke Acquisition Of Westcoast

On November 21, an announcement was made by Westcoast that Duke Energy has received approval from the British Columbia Utilities Commission (BCUC) to acquire indirect control of the public utilities owned wholly or in part by Westcoast Energy and regulated

by the BCUC, namely Pacific Northern Gas, Pacific Northern Gas (N.E.), Centra Gas British Columbia, and Centra Gas Whistler.

Duke and Westcoast also announced that they had received a request for additional information and documents from the Federal Trade Commission (FTC) review of the proposed acquisition of Westcoast Energy by Duke Energy. This request is routine and the companies do not expect the request to have a material impact on the timing of the consummation of the proposed acquisition. If the acquisition arrangement is approved by Westcoast Energy's common shareholders and option-holders, subsequent to the B.C. Supreme Court and finally the other conditions of closing being satisfied or waived, the companies expect the acquisition will be completed during Q1/2002.

Ontario Government Considers Not-For-Profit Option For Hydro One

We note the recent media buzz around the proposal to create a not-for-profit structure for Hydro One. The province is considering all options, including one that could raise up to $14 billion in bonds — approximately $5 billion of which would be available (after repaying Hydro One's existing debt and equity investors) to pay down part of the Old Ontario Hydro's $21 billion in stranded debt. Before this month, the prevailing options were thought to be either the outright sale to another utility company or an initial public offering (IPO) to private investors and stock exchange listing. The not-for-profit option is purported to result in $2 billion – $4 billion more in initial stranded debt retirements.

Hydro One management is opposed to the not-for-profit option, not so much for the lack of ability to use employee share options as incentives, but more for the ramifications for its strategy to become a major player in the North American electricity market. Under this option it would likely not have to pay taxes, which American transmission companies would likely argue was an unfair competitive advantage for Hydro One. Also, without financial flexibility, Hydro One might have fewer resources to invest in new connections to the North American power grid, which could result in the Ontario power market becoming less fully integrated with the North American grid. At first blush this would lower electricity prices in Ontario, if excess energy is bottled up in Ontario. Over the longer term, however, the cost to consumers could increase if inadequate transmission capacity discouraged construction of sufficient generation to meet growing demand.

Some of the province's largest electricity consumers appear to favour the not-for-profit option based on the assumption that this would reduce the special levy on consumption to pay off the stranded assets. For example, currently the levy is approximately 15% of electricity consumed for large consumers such as Dofasco. We believe that this view is erroneous as the levy would not be reduced until the stranded debt is fully defused or repayed. Moreover, there is no assurance that the levy would end significantly earlier as higher up front proceeds from the bond issue could be offset in the long run by lower provincial income tax payments.

Environmentalist groups' responses have been mixed—with some in favour and others opposed.

We favour privatization, as we believe that all stakeholders would be best served over the longer term. While large industrial consumers think they might benefit in the short term through a reduced stranded debt levy, over the longer term the isolation of the Ontario power market and probable broader under investment in new technologies could drive prices up. We believe that agency issues both on the economic as well as environmental front would be mitigated if management were to be accountable to shareholders and not the broad taxpayer base through the government.

The Ontario power market is expected to be deregulated by May 2002, and we believe that a for-profit transmission company could best serve this market. Power companies feel that way as well. TransAlta recently stated that it would not invest further in Ontario until there was more certainty and clarity around deregulation in the province. Bruce Power publicly stated its belief that a private transmission company would have a more efficient, robust, and reliable infrastructure. We note that we are in good company, as Alan Greenspan, the U.S. Federal Reserve chairman, spoke on November 14 to the U.S. Chamber of Commerce about the importance of increased flexibility in electricity transmission and market forces in balancing supply and demand. He cited the need for a vibrant energy policy to foster long-term economic growth, which we believe applies to Ontario as well.

Hydro One To Partner In Merchant Transmission Line Under Lake Erie

Hydro One seems to be operating with the expectation that it will be privatized, as it is acting on its mandate to competitively connect to markets outside Ontario. On November 27, Hydro One and TransEnergie U.S., a subsidiary of Hydro-Quebec, proposed the construction of a 975-MW merchant power line under Lake Erie that could be ready for commercial service by the summer of 2004. The proposed line would be high-voltage direct current (HVDC), enabling power to flow in both directions and originate at a substation not far from the 3,920-MW and coal-fired Nanticoke generation complex, and terminate at one of two substations, either in Ohio or Pennsylvania. Because it would be a merchant line, funding would come from the sale of transmission rights and not impact the cost of transmission within Ontario.

Although Hydro One has 17 interconnections with other systems, congestion in the past led to price spikes in the U.S. Midwest markets in the summers of 1998 and 1999. Ontario typically experiences demand peaks in the winter and is capable of exporting demand south of the border in the summer. Advocates of the new line argue that not only will the new connection increase reliability within the Ontario system, it will also encourage the growth of new generation within Ontario and spur interest in outside generators to send power into the province.

Ontario Electricity Deregulation On Schedule

Deregulation of the retail markets is progressing as scheduled, with the December 14, 2001 deadline for several applications by distributors and wholesale market participants approaching. By that date, distributors must forward a self-certification and market readiness submission to the OEB. Wholesale market participants must file fully executed participant and connection agreements, as well as proof of secure exchange of information capabilities with the IMO. Furthermore, codes, rules, and regulatory approvals are due by the middle of December[1]. This will trigger the market readiness recommendation and government consultation phase, which is due to be completed in mid-January[2].

This milestone will define operation of the wholesale and retail markets, including the following: 1) market rules of the IMO–administered markets; 2) IMO market manuals, technical standards, and interfaces; 3) retail settlement and other OEB codes and standards, including structures of the various rates to be approved by the OEB, and 4) approvals by the OEB of individual rate applications.

2 The OEB and the IMO will advise the Minister of Energy, Science and Technology regarding the readiness of the market participants under the current schedule based on: 1) the readiness of individual market participants; 2) the stability of both wholesale and retail market design, as confirmed in relevant design testing; 3) the readiness of the IMO market systems; and 4) results of self-certification filings by licensed distributors.

Third-Quarter Results

Earnings season came to a completion with the release of Caribbean Utilities' earnings on November 20. Table 4 highlights actual and forecast Q3 EPS for 2001 and actual EPS for 2000. Detailed commentary is available in our Research Highlight for each company, generally published one business day after the earnings reporting date.

Table 4. Third-Quarter EPS Results

	Report Date	Actual 2001	Our Estimate	Consensus Estimate	Actual 2000
Enbridge	November 8	$0.42	$0.46	$0.47	$0.28
TransCanada PipeLines	October 30	0.34	0.34	0.34	0.32
Westcoast Energy	October 21	0.46		0.20	0.22
ATCO	November 1	0.82	0.73	NA	0.74
BC Gas	November 8	(0.58)		(0.39)	(0.34)
Canadian Utilities	October 31	0.65	0.63	0.63	0.64
Caribbean Utilities (US$)	November 20	0.24	0.23	0.22	0.23
Emera	November 2	0.17	0.16	0.14	0.06
Fortis	October 31	0.79	0.55	0.48	0.47
TransAlta	October 18	0.25	0.27	0.25	0.32

Source: CIBC World Markets, First Call.

Table 5. Comparable Valuation, Ratings, And Target Prices – November 30, 2001

Stock Rec.	Symbol	Company	Fiscal Year	Price	52-Week High	52-Week Low	Mkt. Cap. ($ mlns.)	Recent BV	P/BV	EPS 2000	EPS 2001E	EPS 2002E	EPS 2003E	EPS Growth 00-03	P/E 2001E	P/E 2002E	P/E 2003E	Current Dividend	Yield	Total Implied Return	12-mo. Target Price
Pipelines																					
Buy	ENB	Enbridge Inc.	Dec.31	$44.30	$45.55	$33.90	$7,159	$14.67	3.02	$2.17	$2.46	$2.80	$3.09	12.5%	18.0	15.8	14.3	$1.40	3.2%	16.0%	$50.00
Hold	TRP	TransCanada PipeLines	Dec.31	19.97	21.13	14.80	9,512	11.01	1.81	1.22	1.39	1.47	1.51	7.4	14.4	13.6	13.2	0.90	4.5	9.7	21.00
	W	Westcoast Energy	Dec.31	41.00	42.29	29.90	5,059	22.76	1.80	2.51					–	–	–	1.36	3.3	N/A	N/A
		Average Pipelines													**16.2**	**14.7**	**13.8**		**3.7%**		
Utilities																					
Hold	ACO.X	Atco	Dec.31	46.00	54.00	38.00	1,366	26.43	1.74	3.79	4.10	4.37	4.63	6.9	11.2	10.5	9.9	1.04	2.3	16.4	52.50
	BCG	BC Gas	Dec.31	35.00	36.88	29.00	1,341	17.86	1.96	2.06	–	–	–	–	–	–	—	1.32	3.8	–	N/A
Hold	CU	Canadian Utilities	Dec.31	52.00	56.05	43.10	3,297	23.29	2.23	3.59	3.76	3.92	4.22	5.5	13.8	13.3	12.3	1.88	3.6	11.3	56.00
Hold	CUP.U	Caribbean Utilities ($US)	Apr.30	12.05	13.50	11.00	289	3.70	3.26	0.78	0.78	0.87	1.00	8.6	15.4	13.9	12.1	0.62	5.1	11.0	12.75
Hold	EMA	Emera	Dec.31	17.75	18.20	15.55	1,737	11.85	1.50	1.20	1.16	1.18	1.18	(0.6)	15.3	15.0	15.0	0.85	4.8	0.6	17.00
Hold	FTS	Fortis	Dec.31	42.09	44.83	33.55	626	27.50	1.53	2.36	3.20	3.36	3.53	14.4	13.2	12.5	11.9	1.88	4.5	17.3	47.50
Buy	TA	TransAlta Corp.	Dec.31	22.00	30.13	19.15	3,714	11.69	1.88	1.29	1.27	1.55	1.84	12.6	17.3	14.2	12.0	1.00	4.5	22.7	26.00
		Average Utilities													**15.0**	**13.8**	**12.7**		**4.4%**		

[1] EPS estimates for Caribbean Utilities are for the period ending April 30 the following year.
[2] Averages exclude data for ATCO.

Source: CIBC World Markets, Starquote.

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Office national de l'énergie

Canadian Hydrocarbon **Transportation** System

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TRANSPORTATION ASSESSMENT • August 2005

Canada

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TRANSPORTATION ASSESSMENT • AUGUST 2005

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Acronyms and Abbreviations

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
B.C. System	TCPL B.C. System
Chevron	Chevron Canada Limited
Cochin	Cochin Pipe Lines Ltd.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
FFO	Funds from Operations
Foothills	Foothills Pipe Lines Ltd.
FT	Firm transportation
IPI	Implicit Price Index
IT	Interruptible transportation
LNG	Liquefied natural gas
M&NP	Maritimes and Northeast Pipeline
MPL	Montreal Pipe Line
NEB or Board	National Energy Board
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Equity
S&P	Standard & Poor's
SOEI	Sable Offshore Energy Inc.
T-South	Transportation South Zone on Westcoast
Terasen (TMPL)	Terasen Pipelines (Trans Mountain) Inc.
TNPI	Trans-Northern Pipeline Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.

Units

Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
MMcfd	Million cubic feet per day
GJ	Gigajoule
m^3/d	Cubic metres per day
$10^3m^3/d$	Thousand cubic metres per day
MW	Megawatt

FOREWORD

As part of its regulatory mandate, the National Energy Board (the Board or NEB) continually monitors energy and transportation markets to ensure that Canadians derive the benefits of economic efficiency. To further assist in its monitoring efforts, the Board identified a need in its *2004-2005 Report on Plans and Priorities* to implement a performance measurement system for pipeline tolls and tariffs, including the financial health of the pipeline industry.

This report provides an assessment of how the Canadian hydrocarbon transportation system is currently functioning and sets out the framework the Board will use for future assessments.

The data contained within this report is based on publicly available information collected and monitored by NEB staff. In identifying some of the emerging issues around the transportation system, the Board also benefited from discussions with members of the investment community. A draft of the report was sent to the Canadian Energy Pipeline Association and the Canadian Association of Petroleum Producers for comment prior to its release.

Any comments on the report or suggestions for further analysis can be directed to:

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If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as it can submit any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

INTRODUCTION

The Canadian hydrocarbon transportation system moves over $100 billion in petroleum products and natural gas to Canadians and export markets each year. In 2004, energy export revenue was almost $59 billion, accounting for about 15 percent of total Canadian exports. Energy is essential to our daily lives and the ability of the pipeline transportation system to reliably and efficiently deliver this energy is critical to our country's economic well-being. The Board regulates the physical and financial operations of pipelines that cross interprovincial boundaries and the international boundary.

The Board has developed five corporate goals to ensure that its regulatory program provides value to Canadians. The third goal is that "Canadians derive the benefits of economic efficiency". To determine whether this goal is being achieved, the Board monitors energy and transportation markets for evidence that they are working well.

Each year the Board issues various Energy Market Assessment reports that focus on different aspects of Canadian energy markets. This is the first time that the Board has issued a report that focuses on the functioning of the Canadian hydrocarbon transportation system.

This report is similar to the Board's other market monitoring reports and its intent is to assess how well the Canadian hydrocarbon transportation system is working and to outline a system to monitor and measure the performance of the transportation system from year to year. This report should not be read as a regulatory document, like a Reasons for Decision. In this report, the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. Thus, the factors on which the functioning of the transportation system is assessed are not the same as those which are applied in a regulatory proceeding.

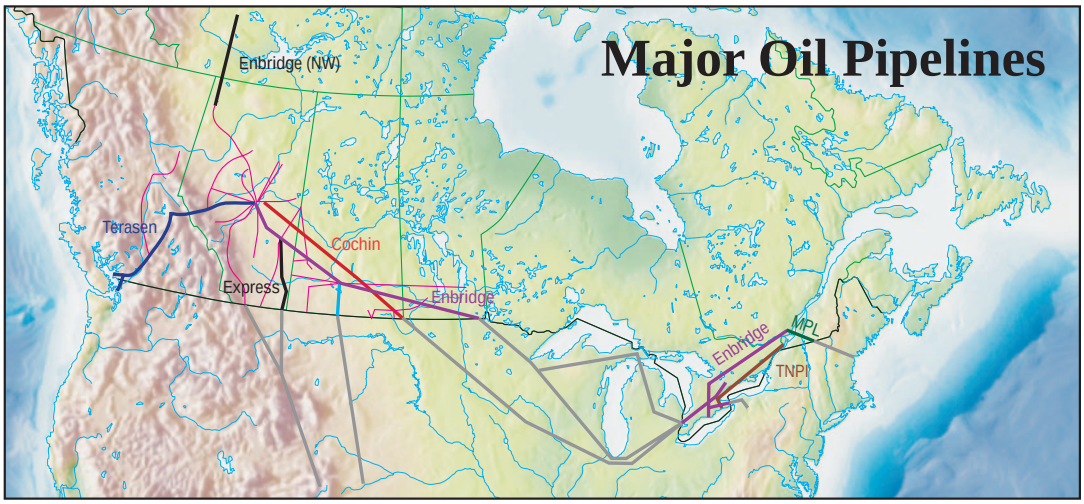
For the transportation system to work well, the Board believes that the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move products to consumers who need them;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

To assess the extent to which these outcomes are being achieved, the Board used publicly available data for Group 1 regulated companies (see Figure 1). This group comprises the major pipeline companies that are subject to ongoing regulatory oversight by the Board. As these companies represent a major part of the Canadian transportation system, the data from these companies provides a good view into the overall functioning of the transportation system.

FIGURE 1

Gas and Oil Pipelines Regulated by the National Energy Board



THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

2.1 Adequacy of Pipeline Capacity

A key measure of the efficient operation of energy markets is that there is adequate pipeline capacity to transport crude oil, refined products, natural gas and natural gas liquids from producing regions to market areas.

This section examines the following factors to assess the current adequacy of the pipeline capacity:

- price differentials compared with firm service tolls for major transportation paths
- capacity utilization on pipelines; and
- the degree of apportionment on major oil pipelines.

The Board has generally taken the view that it is better to have some excess pipeline capacity than to have inadequate capacity. While there are costs associated with having excess capacity in terms of higher tolls for shippers, the costs associated with insufficient pipeline capacity are generally greater. When there is inadequate take-away capacity, natural gas or oil production is shut-in or shipped to less attractive markets, resulting in foregone revenues for producers, foregone royalty revenue for governments, higher commodity prices for downstream consumers, an inefficient allocation of supply and a negative signal to investors in the upstream sector. The assurance that adequate capacity is available to serve various market regions provides a strong incentive to invest in exploration and development.

Further, some excess capacity in the system provides flexibility in the market. For example, when gas demand and prices are high in California because of poor hydro-electric conditions, Canadian producers would like to move gas to that market. When cold weather strikes the U.S. Northeast and prices in that market increase, the existence of some spare capacity allows producers to swing supply to that market, meeting consumers' needs and helping prices to stabilize.

The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines (e.g., in 2004 the value of products transported was approximately $100 billion compared with $4.5 billion for the cost of providing transportation service).

2.1.1 Price Differentials and Firm Service Tolls

One measure of adequacy is based on the principle that, if adequate capacity exists, the price differential (or basis) between two points on a pipeline should be equal to or less than the cost of

transportation. As long as the price differential is less than the firm service toll plus fuel, the market is demonstrating that there is adequate pipeline capacity between the two pricing points. When there is inadequate pipeline capacity between two market points, the basis will exceed the cost of transportation. In a market with adequate capacity, sellers would generally redirect their product to the higher price market, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use this measure, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below; one for transportation on TransCanada PipeLines Limited (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

Figure 2 shows the basis between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The fact that the basis is consistently lower than the firm service toll demonstrates that there generally has been excess capacity available on TransCanada since at least January 2001, although it appears that capacity between these two points has firmed up during the summer months since July 2002.

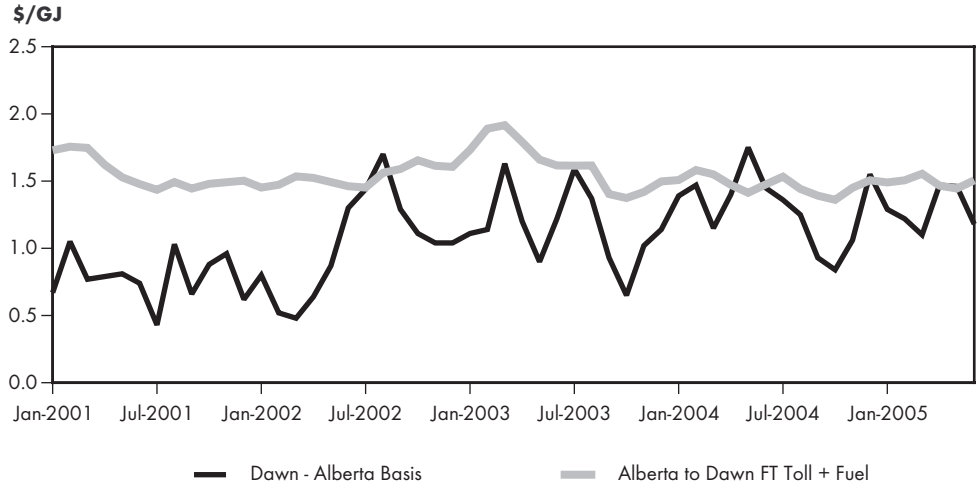
Figure 3 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Except for a few months, the basis has been lower than the transportation costs since February 2001, which indicates that there has been adequate capacity in place since that time[1].

Dawn-Parkway Corridor

Although there is inadequate pricing data available, there is evidence that capacity is tight on the Dawn-Parkway corridor of the Union Gas system. After the close of a binding open season in December 2004, Union signed contracts with 22 parties for an expansion of its system between Dawn and Parkway. Following the consideration of Union's facilities application, the Ontario Energy Board

FIGURE 2

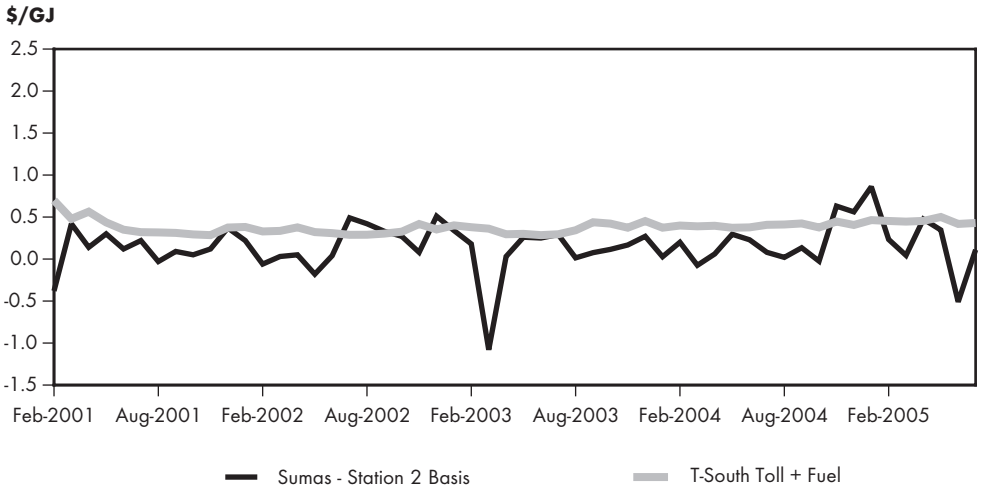
Dawn - Alberta Basis vs. TransCanada Toll and Fuel



1 The negative price differential at March 2003 may be a data anomaly.

FIGURE 3

Sumas - Station 2 Basis vs. Westcoast T-South Toll and Fuel



approved the expansion which is expected to be in service by November 2006. While not regulated by the NEB, this corridor is a key link between the Dawn hub and markets in eastern Canada and the U.S. Northeast.

2.1.2 Capacity Utilization on Major Routes

Where good pricing data is not available at major injection and delivery points on a pipeline system, another measure of adequate capacity is to monitor pipeline throughput compared with capacity. Capacity utilization is monitored for most large pipelines regulated by the Board.

The following figures show pipeline average monthly throughput compared with capacity on some of the largest pipeline systems regulated by the NEB, including TransCanada, Westcoast, Alliance Pipeline Ltd. (Alliance), Enbridge Pipelines Inc. (Enbridge), Terasen Pipelines (Trans Mountain) Inc. (Terasen (TMPL)) and Express Pipeline Limited Partnership (Express).

The volumes shown on Figure 4 are average monthly throughput[2] on the TransCanada Mainline and are approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan. These volumes are compared with the design capacity of TransCanada's prairie line. Figure 4 shows that since April 2003, the prairie line has been operating at between 70 to 80 percent of capacity.

Figure 5 shows the average monthly throughput on Westcoast's Southern Mainline compared with capacity between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with more volumes being transported during the peak winter months and less volumes being transported during the summer months.

In Figure 6, throughput on Alliance's system is compared with the firm service contracted capacity of 37,534 $10^3m^3/d$ (1,325 MMcfd) and physical capacity, which has been calculated as the sum of the contracted capacity and capacity made available for Authorized Overrun Service (AOS). As shown, Alliance's capacity has been virtually 100 percent utilized since the commencement of its operations because of the high contract level and the offering of AOS, priced at only the cost of fuel, which has filled any additional capacity.

2 Daily fluctuations in throughput are not shown on the figure.

FIGURE 4

TransCanada Mainline Throughput vs. Capacity

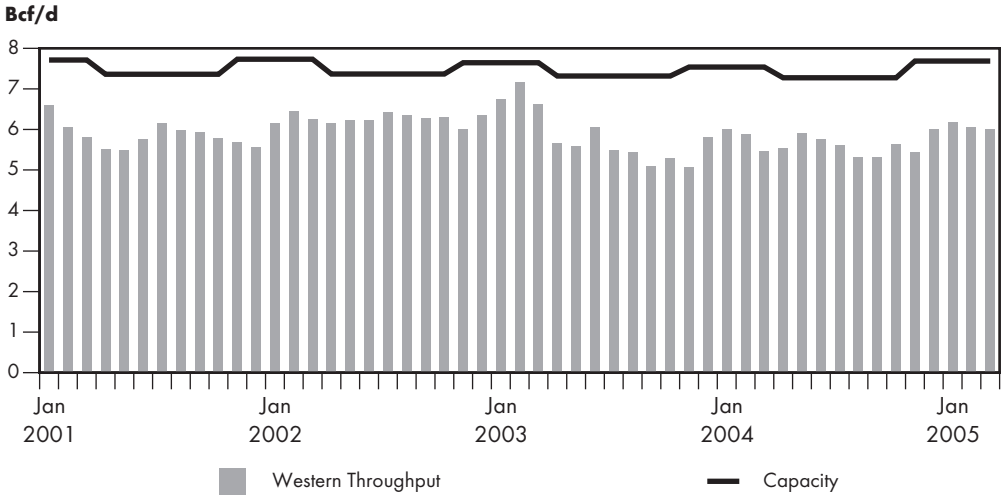
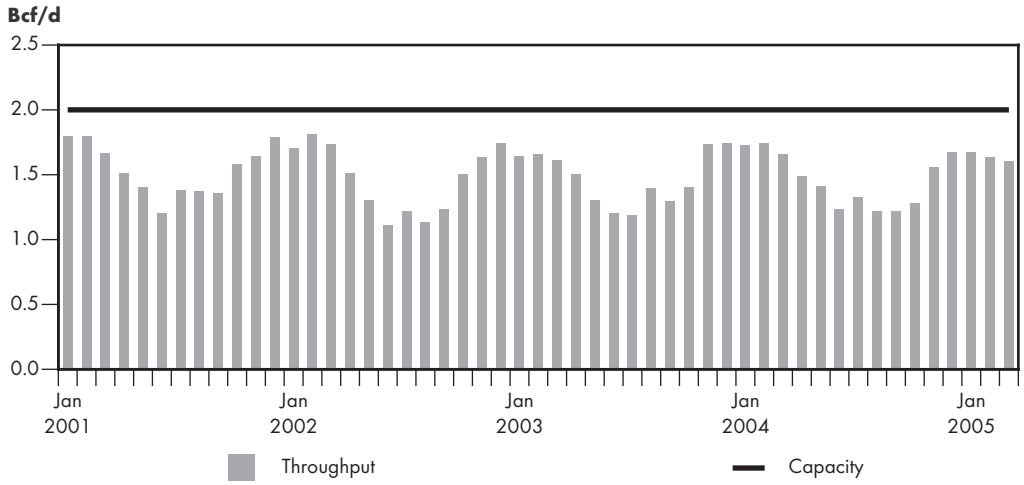


FIGURE 5

Westcoast Mainline Throughput vs. Capacity



It is somewhat difficult to assess utilization of the Enbridge system because it consists of several lines, most of which are dedicated to carrying specific grades of crude oil or natural gas liquids. As shown in Figure 7, since January 2001 Enbridge's mainline has been operating, on an overall average, at levels as low as 68 percent of capacity and as high as 86 percent of capacity. In the first quarter of 2005, Enbridge's mainline was operating at around 74 percent of capacity. Certain lines, particularly Lines 4 and 9 have been operating at or close to full capacity, with some apportionment (see section 2.1.3).

Terasen (TMPL) was operating at near capacity in 2003-04, with apportionment in January and March 2004. Given the high utilization rate, expected rising demand for pipeline space related to expected production growth in the oil sands, and increased shipments of heavy crude oil, Terasen (TMPL) applied in December 2003 for a 4 300 m^3/d expansion. The Board approved this expansion and it went into service in September 2004. In the first quarter of 2005, Terasen (TMPL) operated at approximately 60 percent of capacity, mainly because of refinery turnarounds on the west coast (see Figure 8).

FIGURE 6

Alliance Throughput vs. Capacity

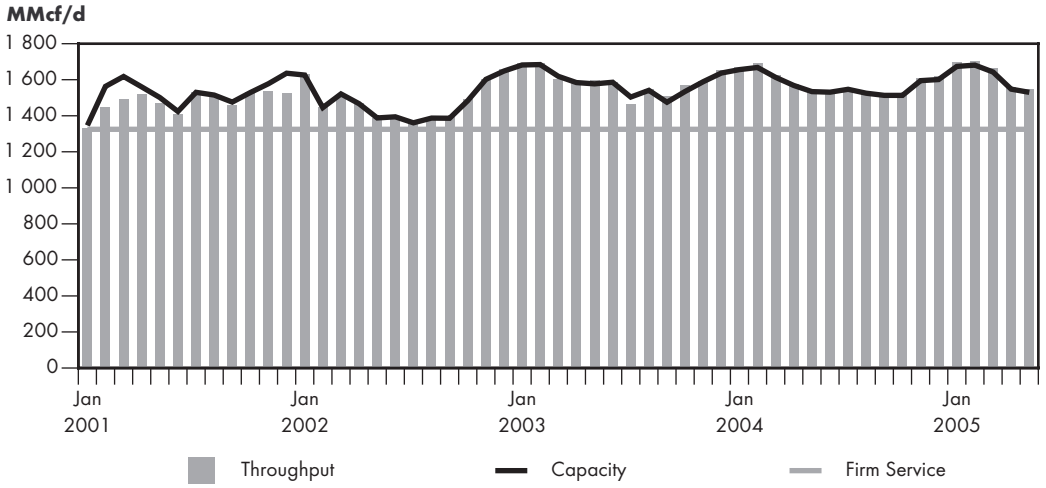
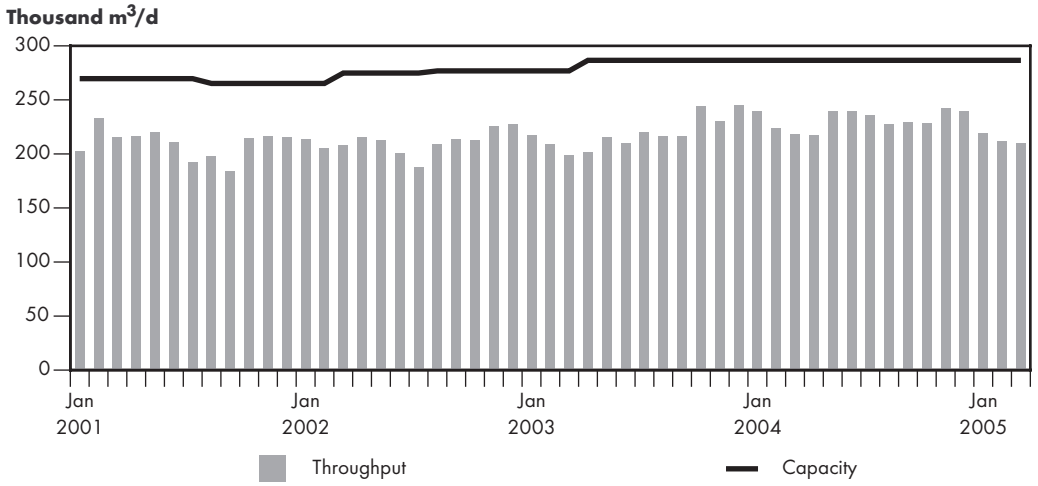


FIGURE 7

Enbridge Pipeline Throughput vs. Capacity



Express Pipeline Limited Partnership has been operating at full capacity for several years; at times exceeding 100 percent of its rated capacity (see Figure 9). On 1 April 2005, an expansion of 17 100 m^3/d was completed. Unlike Enbridge or Terasen (TMPL), Express primarily operates with long-term financial commitments with its shippers. Given that shippers have financially committed to the system, they will tend to use their available space on Express before shipping on other systems.

2.1.3 Apportionment

Oil pipelines operate for the most part as common carriers. On common carriers, shippers nominate their desired volumes for delivery into the pipeline on a monthly basis and have no contractual rights to the pipeline's capacity. Lack of adequate pipeline capacity occurs when shippers nominate more oil or oil products for transport than the pipeline can carry that month. When this happens, each of the shippers that nominate volumes is allotted or "apportioned" a share of the available capacity based on the capacity allotment agreement for each pipeline. Some recent apportionment data for Enbridge, Terasen (TMPL) and Cochin Pipe Lines Ltd. (Cochin) are shown below.

FIGURE 8

Terasen (TMPL) Throughput vs. Capacity

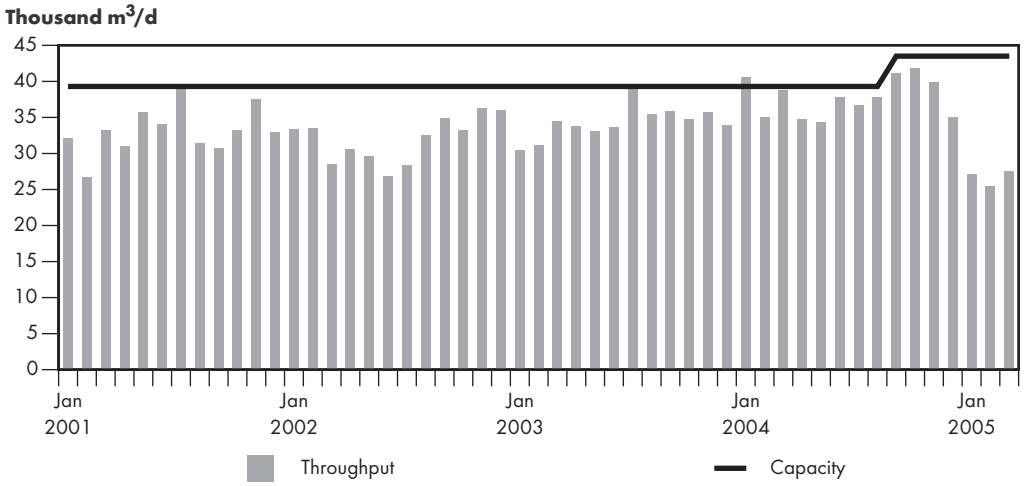
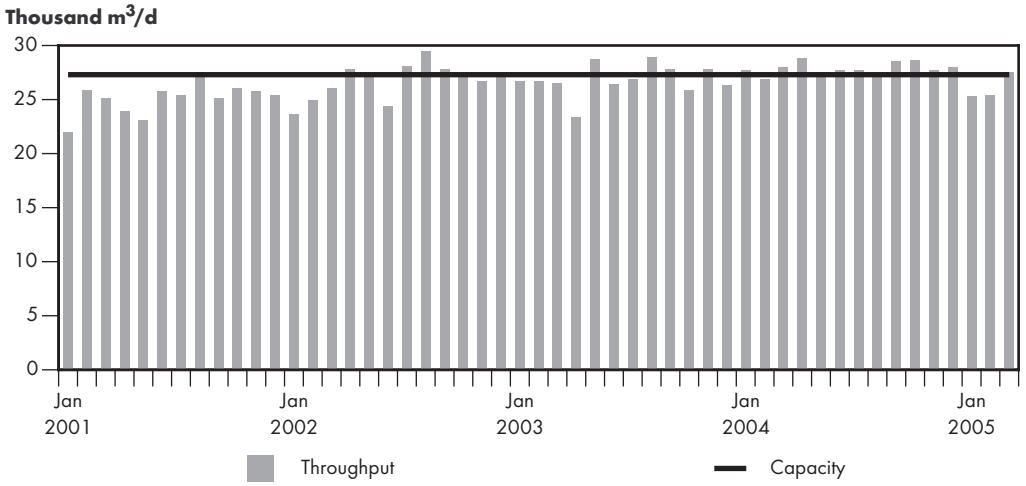


FIGURE 9

Express Throughput vs. Capacity



Enbridge

Enbridge's Line 2 and 4 are dedicated to the transportation of heavy crude oil, while Line 3 is dedicated to light and medium crude oils. In the first quarter of 2005, Line 4 was either marginally over subscribed or fully subscribed. In the third quarter of 2005, Enbridge is planning to switch service in Lines 2 and 3, thereby increasing heavy capacity by 39 000 m^3/d.

Enbridge's Line 9 has a capacity of 38 150 m^3/d and transports oil from Montreal to Sarnia. As shown in Table 1, apportionment has occurred fairly frequently on this line. One reason for this apportionment is increased shipments of crude oil produced from the Hibernia and Terra Nova fields which have high wax content and decreases operating capacity. Another reason is that foreign crude oil has been attractively priced and imports have been high in several months.

TABLE 1

Enbridge Apportionment

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Line 4 Apportionment	0%	0%	0%	6%	0%	0%	1%	0%
Throughput ($10^3m^3/d$)	98.1	100.5	101.4	119.3	113	114.2	114.8	104.7
Line 9 Apportionment	21%	18%	0%	0%	4%	10%	0%	0%

TABLE 2

Terasen (TMPL) Apportionment

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Apportionment	24%	14%	14%	0%	0%	0%	0%	13% L 62% D
Throughput ($10^3m^3/d$)	41.2	41.8	39.8	34.9	27.2	25.4	28.3	37.2

Terasen (TMPL)

On Terasen (TMPL), apportionment is calculated separately for volumes delivered to land-based and Westridge Dock destinations (shown as L and D respectively in Table 2). Apportionment in September through November 2004 was attributed to land-based nominations that were due to increased demand as well as maintenance on the system that reduced available capacity. Even with the capacity expansion that was completed in September 2004, there was apportionment in November due partly to greater demand by Washington State refiners. From December 2004 to March 2005, throughput fell and there was no apportionment for those months. The April 2005 apportionment of 13 percent for land-based volumes likely reflects increased nominations from the Washington refineries following plant turnarounds. The 62 percent apportionment for the Westridge Dock could reflect increased test shipments of heavier type crude oils.

As a result of periods of apportionment on Terasen (TMPL) since 2003, two applications have been filed with the Board. One is from Chevron Canada Limited (Chevron) for an order designating Chevron's refinery at Burnaby, B.C. as a priority destination for unapportioned delivery of crude oil from Edmonton. The second application was filed by Chevron Standard Limited, Neste Canada Inc. and Chevron for an order designating Chevron's refinery at Burnaby, B.C. as a priority destination for the unapportioned delivery of iso-octane from Edmonton.

Cochin

The capacity on Cochin is dependent on the type of product that is transported in the line and the time of year. Propane, ethane, ethylene and field-grade butane can all be transported on the line but the amount of ethylene nominated in a month affects the capacity. When there is a large amount of ethylene in the line, the capacity is reduced significantly. Cochin is still on pipeline restrictions since a rupture on the U.S. portion of the pipeline and a subsequent fire in 2003.

There was no apportionment in the first quarter of 2005, but pressure restrictions continue to limit capacity on Cochin. Apportionment is anticipated to occur between June and September 2005 due to a scheduled line shut-down for hydro-testing.

TABLE 3

Cochin Apportionment

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Apportionment	32%	0%	0%	5%	0%	0%	5%	0%
Throughput ($10^3m^3/d$)	7.4	11.4	11.0	10.3	12.3	8.7	7.6	9.4

Wascana Pipeline

As operator of the Wascana Pipeline, PMC (Nova Scotia) Company received notice that the Bridger Pipeline would not be able to accept deliveries of crude oil from Wascana south of the first Bridger Pipeline pump station at Poplar, Montana because of integrity concerns. As a result of this constraint on the U.S. side, Wascana has been operating at greatly reduced rates. The Bridger Pipeline is currently investigating and repairing a large number of anomalies that were identified on its system. While it is still too early to determine with any certainty when the Bridger Pipeline will return to normal operation, the company's target is the end of August 2005.

2.2 Index of Pipeline Tolls

Another indicator of the efficiency of the transportation system is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices. The Board assesses this by analyzing the change over time in a benchmark toll for each major pipeline (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South export toll). Given the nature of cost of service regulation, pipeline tolls may increase simply because a major capital project was undertaken to meet shippers' needs. Nonetheless, if a benchmark toll increases sharply, it could indicate an issue in transportation markets (e.g., falling throughput or contract demand).

Gas Pipelines

Figure 10 compares the tolls for TransCanada, Westcoast and Foothills Pipe Lines Ltd. (Foothills) with the Implicit Price Index (IPI), Non-residential structures[3], normalized to the year 1997.

The increase in TransCanada's Eastern Zone toll between 1997 and 2001 is mainly attributed to the large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. The toll has been tracking the IPI fairly closely since 2001.

In 2000, Westcoast's T-South export toll increased over 10 percent from the previous year primarily because of non-routine pipeline integrity costs. The export toll began moving more closely to the IPI in 2001.

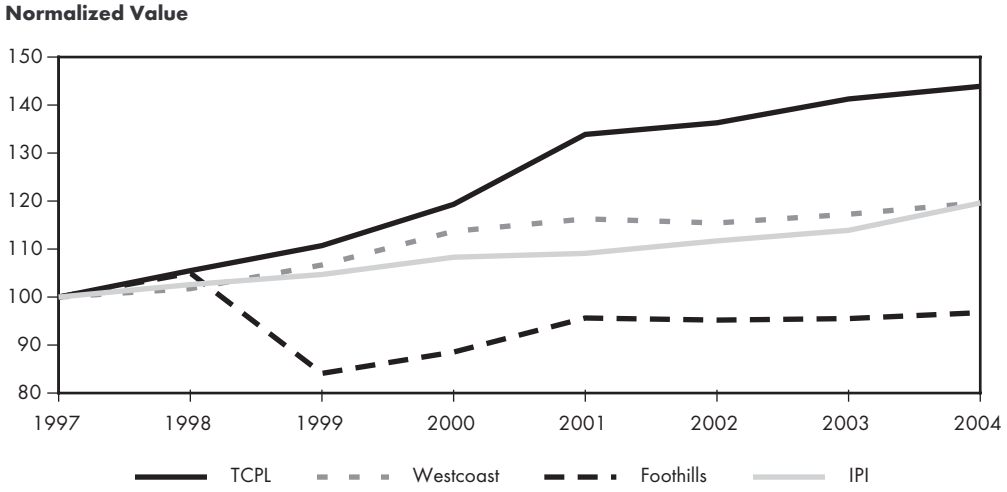
After declining in 1999 as a result of a cost-effective expansion of its system, Foothills' Zone 9 tolls have remained fairly stable. In addition, Maritimes & Northeast Pipeline's (M&NP) tolls have been relatively constant at around $0.66-68/GJ since it began operations in 2000 and Alliance's tolls have remained flat at $0.77/GJ since it began operations in 2001.

3 Statistics Canada suggested this index as being a suitable index for pipeline services.

Statistics Canada - CANSIM Series v3840577 - Table 384-0036: Implicit price indexes, Gross Domestic Product (GDP), PEA; Canada; Business gross fixed capital formation, non-residential structures (Index, 1997=100)

FIGURE 10

Gas Pipeline Tolls and the Implicit Price Index (Normalized to the Year 1997)



Oil Pipelines

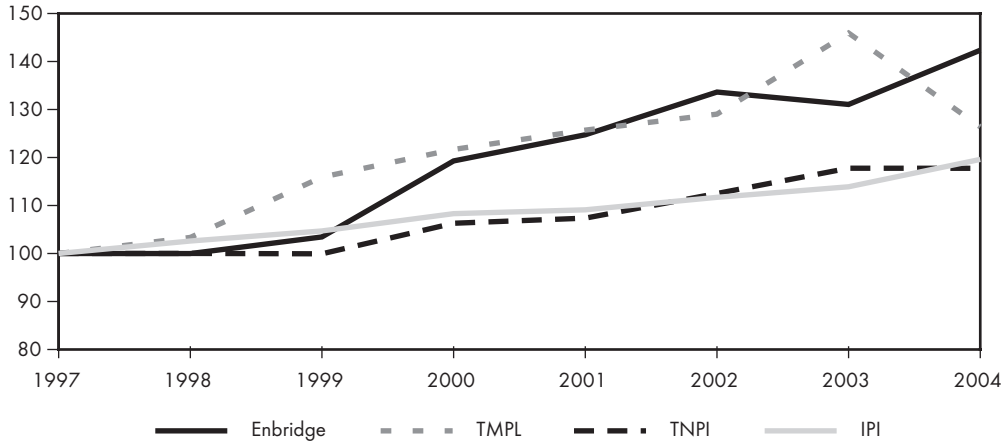
Figure 11 below shows benchmark tolls for Enbridge, Terasen (TMPL) and Trans-Northern Pipelines Inc. (TNPI) compared with the IPI, Non-residential structures, normalized to the year 1997.

In 2000, Enbridge's tolls (Edmonton to International border) increased because throughput levels were unexpectedly low in 1999. Under its negotiated settlement, Enbridge was able to recapture the shortfall in the ensuing years. The increase in 2004 tolls was mainly because Enbridge was operating at approximately 80 percent capacity utilization, as throughput has not filled recent capacity expansions. The full fixed costs are spread across lower volumes, resulting in higher tolls.

In 1999, Terasen (TMPL)'s tolls (Edmonton to Burnaby) increased because of low forecasted throughput (the 1999 forecast was 17.9 percent lower than the 1998 forecast and the toll is calculated based on forecast throughput). In 2004, Terasen (TMPL)'s tolls decreased, mainly because of the

FIGURE 11

Oil Pipeline Tolls and the Implicit Price Index (Normalized to the Year 1997)



disposition of 2003 deferrals for higher revenue and lower costs and slightly higher throughput starting in October 2004.

TNPI's tolls (Oakville to Montreal) have generally moved in tandem with the IPI since 1997.

2.3 Shipper Satisfaction

Shipper satisfaction is also another key measure of the efficiency of the transportation system. The Board uses the following tools to measure shipper satisfaction with the services they receive from pipeline companies:

- an annual survey;
- feedback through informal discussions with shippers and other stakeholders; and
- formal complaints filed with the Board.

2.3.1 NEB Pipeline Services Survey

In June 2004, the Board established an annual Pipeline Services Survey to obtain direct feedback from the shippers of ten major NEB-regulated pipeline companies on the level of service provided by those companies. The survey was also used to obtain feedback on the Board's performance in implementing its regulatory role with respect to tolls and tariffs.

In January 2005, the first Pipeline Services Survey was administered. Companies sent the survey to each of their active shippers, who then returned their responses directly to the Board. The overall response rate to the survey was 23 percent.

After analyzing the survey responses, the Board published a summary of the results in aggregate. The aggregate results include the industry average and distribution of responses for each question and a summary of any major themes or trends. In addition, the Board provided each pipeline and those shippers that participated in the survey with detailed company-specific results. Those results included the pipeline company's average rating and distribution of responses for each question and the verbatim comments received from shippers, with the source of those comments removed.

Figure 12 shows the aggregate results for the first survey question, which asked shippers to rate the overall quality of service provided over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The figure shows that shippers, on average, are reasonably satisfied with the services provided by pipeline companies[4].

The survey results indicated that shippers believe the pipeline companies are doing well in the following areas:

- physical reliability of operations;
- timeliness and accuracy of invoices and statements; and
- timeliness and usefulness of operations information.

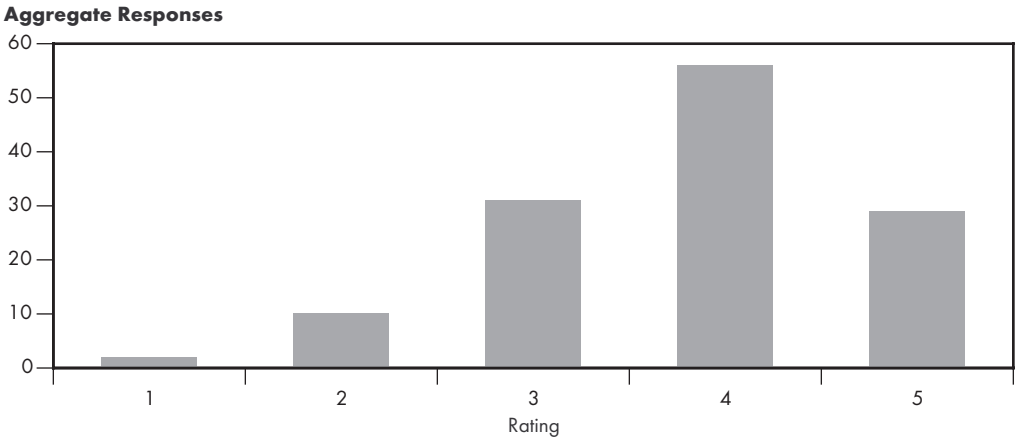
The areas where shippers believe that pipeline companies could improve the most are:

- make tolls more competitive;

4 The industry average is the average of all responses across all pipelines.

FIGURE 12

Overall Quality of Service (Industry Average, 3.78)



- exhibit an attitude of continuous improvement and innovation; and
- work towards fair and reasonable solutions when resolving issues.

Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, go to www.neb-one.gc.ca/Publications/ and look under Survey Results.

2.3.2 *Informal Monitoring*

Informal monitoring involves face-to-face discussions between NEB staff and pipeline companies, shippers, provincial regulators and other stakeholders, such as members of the investment community. It enables NEB staff to seek views on industry issues and concerns, including pipeline performance and perceptions about regulatory processes. These discussions also provide the Board with an opportunity to gauge the efficiency of transportation systems and can provide an early signal of the need for leadership in some areas of economic regulation[5].

Some examples of comments received from stakeholders during informal monitoring meetings included:

- Where possible, tolls should be set for multiple years (e.g., three to five years) at a time. This practice would provide cost savings, more toll certainty and avoid re-examining the same material over and over. Some shippers stated that an NEB policy statement would encourage this outcome (similar to what the Federal Energy Regulatory Commission does with its *Notice of Proposed Rulemakings*). This suggestion was supported by a number of members of the investment community.
- A mechanism is needed for the Board to hear shipper concerns on a regular basis. With negotiated settlements, shippers feel that the Board gets little information on their concerns.

5 The Board is, of course, bound by its Code of conduct not to discuss any matter with outside parties that is currently a matter before the Board in a regulatory proceeding. See the Board's Web site for a copy of the Code of conduct.

2.3.3 *Formal Complaints*

The number and nature of formal shipper complaints to the Board is another indicator of how satisfied shippers are with pipeline services. A sizeable number of complaints could indicate that a problem needs to be addressed. There have only been a few complaints filed in the last two years that have required a formal process before the Board.

2.4 Pipeline Financial Viability and Ability to Raise Capital

The final measure of the efficiency of the transportation system is the financial strength of the pipeline companies. This section looks at the financial viability of several NEB-regulated pipeline companies and their ability to raise capital on reasonable terms and conditions to invest in infrastructure. To undertake this assessment, the following factors are examined: financial ratios, credit rating reports and equity analyst assessments.

As noted in the Introduction, it is not the intention of this report to assess factors that would be examined in a regulatory proceeding on cost of capital such as the comparable earnings standard or the capital attraction standard. Rather, the purpose of this report is to provide a broad assessment as to whether the Canadian transportation system is working and one factor in that regard is whether it is able to efficiently expand to meet the needs of producers and end-use customers.

2.4.1 *Financial Ratios*

Financial ratios are useful indicators of a company's performance and financial situation. They can be used to evaluate a company's liquidity, operating performance, growth potential and risk. Evaluating financial ratios is most meaningful when the ratios for a particular company are tracked over time or compared with industry benchmarks. Care must always be exercised in collecting and interpreting financial ratios for pipeline companies given that some financial information pertains to their larger parent companies which may include non-regulated assets.

Some key ratios used to assess the financial viability of pipeline companies include interest coverage ratios, funds from operations to total debt, return on equity (ROE) and total debt to equity. A few of these ratios are discussed below.

Interest Coverage Ratios

Interest coverage ratios measure how many times interest payments could be made with a company's earnings before interest expenses and income taxes are paid. From a bondholder's perspective, interest coverage is an indicator of whether a company could have problems making its interest payments. From an equity holder's perspective, this ratio helps to give some indication of the short-term financial viability of the company.

One formula used to determine the coverage of interest is Earnings Before Interest and Taxes (EBIT) divided by Annual Interest Expense. Another coverage ratio that focuses on cash flows rather than accounting income is funds from operations (FFO) interest coverage. FFO interest coverage data are not included in this report.

A higher coverage ratio is typically better for both bondholders and equity investors. From a bondholder's perspective, a high coverage ratio indicates a low probability that the firm will fail to

meet its interest obligations in the near term. For stock investors, a high ratio indicates that a company is relatively solvent.

Table 4 shows the EBIT interest coverage ratios for Group 1 pipeline companies as calculated by the Dominion Bond Rating Service (DBRS). Most interest coverage ratios are in the 2-3 times range, except for Terasen (TMPL) which has a coverage ratio many times higher than its peers. The reason for this higher ratio is primarily because of Terasen (TMPL)'s common equity ratio of 45 percent, which means it carries less debt. Table 4 also shows that the coverage ratios for most companies are stable or improving over time.

DBRS notes that interest coverage ratios for Canadian pipelines are often lower by 1.0 to 1.25 times than those for U.S. pipelines. It cites the following factors as contributing to these lower coverage ratios:

- lower allowed returns on equity (typically 200 basis points);
- lower allowed deemed common equity ratios of 30 percent to 35 percent in Canada; and
- flow-through tax accounting in Canada versus the normalized method in the U.S. (which allows for the recovery of deferred income taxes in tolls).

Despite the lower coverage ratios as noted by DBRS, none of the major NEB-regulated companies has had a problem servicing their debt obligations.

Return on Equity

Return on Equity (ROE) is a common measure of financial performance and is frequently used when evaluating and comparing companies. The ROE a company earns can be expressed financially as net income divided by common equity. However, for NEB-regulated pipeline companies, this ratio is expressed as the return on the equity portion of the rate base that is approved by the Board.

Table 5 shows the actual ROE for several Group 1 pipeline companies from 1999 to 2004 along with the NEB-approved ROE in accordance with the RH-2-94 Formula[6]. Alliance, Enbridge, M&NP and Terasen (TMPL) are not subject to the NEB-approved ROE as they all have negotiated a different

TABLE 4

EBIT Interest Coverage Ratios

	2000	2001	2002	2003
Alliance	-	1.85	1.92	1.85
Enbridge	2.80	2.84	3.02	-
Foothills	2.16	2.16	2.39	2.41
M&NP	1.55	1.82	2.05	-
Terasen (TMPL)	3.62	4.69	6.12	7.03
TQM	1.99	2.15	2.36	2.36
TransCanada	1.97	2.16	2.32	2.36
Westcoast	1.58	1.99	2.14	1.85

6 Formula used to determine the rate of return on common equity for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, as amended to eliminate rounding.

TABLE 5

Return on Equity for the Period 1999 to 2004

	1999	2000	2001	2002	2003	2004
Alliance	-	11.21	11.25	11.25	11.25	-
Enbridge	11.70	11.20	12.20	13.00	-	-
Foothills	9.58	9.90	9.61	9.53	9.79	9.56
M&NP	-	13.80	14.20	12.95	12.31	13.75
Terasen (TMPL)	18.50	17.50	19.60	20.40	20.40	-
TQM	9.94	9.96	10.21	9.80	10.21	9.84
TransCanada	9.64	9.99	9.72	9.95	10.18	10.18
TCPL B.C. System	9.58	9.90	6.86	9.53	8.21	8.51
Westcoast Field Services	-	-	13.62	14.87	6.76	11.63
Westcoast Transmission	11.68	12.68	15.84	13.44	12.93	10.28
NEB RH-2-94 Formula	9.58	9.90	9.61	9.53	9.79	9.56

Source: DBRS (Enbridge, Terasen); NEB Surveillance and Annual Reports (all others); dash indicates not available

ROE with their shippers[7]. Also, Westcoast's Field Services Division is not subject to the formula as its tolls for gathering and processing services are negotiated individually with shippers.

The ROE numbers for Enbridge and Terasen (TMPL) have been taken from their DBRS Credit Rating reports as those companies currently do not file NEB surveillance reports. As such, the numbers are somewhat higher than one would normally expect and might include some non-regulated income in the calculations (e.g., Terasen (TMPL)'s income includes $6 to $7 million annually of dividend income from its parent, Terasen Inc.). The complete details of these credit rating reports should be read before comparing the ROE for Enbridge and Terasen to the other companies listed in Table 5.

2.4.2 *Credit Ratings*

In Canada, credit ratings are determined by three independent credit rating agencies, DBRS, Moody's and Standard & Poor's (S&P). See Appendix 1 for a comparison of the rating scales for DBRS and S&P. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, the use of credit ratings as an accurate measure of the performance for a regulated pipeline owned by a company that has both regulated and non-regulated operations, such as TransCanada and Enbridge, has to be interpreted with some care. In addition, credit ratings are somewhat subjective in that the rating imposed on a company is the expert opinion of an investment analyst, which may result in different ratings by different firms.

DBRS

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While the key considerations will vary industry by industry, some of the common factors that are considered for most ratings are: core profitability; asset quality; strategy and management strength; and financial and business risk profile.

7 Negotiated ROE for Alliance is 11.25 percent and for M&NP is 13.0 percent.

For pipelines, electric and gas utilities, the following factors are also important considerations in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated vs. non-regulated activities.

The credit ratings for the Group 1 pipeline companies shown in Table 6 indicate that the ratings have remained stable from 1999 to the present. Alliance has improved from BBB(high) to A(low).

Standard & Poor's

An S&P credit rating is a current opinion of a company's overall financial capacity to pay its financial obligations. S&P bases its ratings on the overall creditworthiness of the corporation. Therefore, the rating of a wholly-owned subsidiary company, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent. This opinion focuses on the company's capacity and willingness to meet its financial commitments as they come due and may also apply to specific financial obligations. The rating histories for several Group 1 pipeline companies are provided in Table 7.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

TABLE 6

DBRS Credit Rating History – Senior and Subordinated Debt

	1999	2000	2001	2002	Current
Alliance	BBB(high)	BBB(high)	A(low)	A(low)	A(low)
Enbridge	A(high)	A(high)	A(high)	A(high)	A(high)
M&NP	A	A	A	A	A
Terasen (TMPL)	A(low)	A(low)	A(low)	A(low)	A(low)
TQM	A(low)	A(low)	A(low)	A(low)	A(low)
TransCanada	A	A	A	A	A
Westcoast	A(low)	A(low)	A(low)	A(low)	A(low)

TABLE 7

S&P Credit Rating History

	2000	2001	2002	2003	2004
Enbridge	A/Stable	A-/Negative	A-/Negative	A-/Stable	A-/Stable
Terasen (TMPL)	BBB+/Stable	BBB+/Stable	BBB+/Watch Neg	BBB/Stable	BBB/Stable
TQM	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable
TransCanada	A-/Stable	A-/Stable	A-/ Watch Neg	A-/Negative	A-/Negative
Westcoast	A-/Negative	A-/Stable	A/Negative	BBB/Stable	BBB/Positive

Each of these agencies has expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by the credit rating agencies indicate that NEB-regulated companies are all within investment grade.

2.4.3 Access to Capital Markets

As mentioned in the Introduction, pipeline companies must be able to access capital to expand and maintain their systems to adequately meet the evolving needs of the marketplace.

The most straightforward test of a pipeline company's ability to finance new capacity is market evidence of their ability or inability to finance major new construction. However, there has not been much pipeline construction in the last few years because natural gas production from the Western Canada Sedimentary Basin (WCSB) has hit a plateau and adequate pipeline capacity is in place. While there has been some recent expansion of oil pipeline capacity, no really large investments have been made. Thus, the question to ask is whether or not pipeline companies would have any difficulty in financing new projects when they arise.

To answer this question, the Board met with credit rating agencies, suppliers of capital and equity analysts in the investment community to discuss their views on the ability of Canadian pipelines to access capital markets, their general criteria for assessing NEB-regulated pipelines, and their views on the current regulatory environment in Canada.

On the primary question of access to capital, all of the organizations consulted indicated that Canadian pipelines should have no difficulty raising capital at reasonable cost at this time. For example, they believed that there should be no major challenges in financing a pipeline such as the Mackenzie Valley natural gas pipeline or additional oil pipelines to carry growing production from the oil sands. It was noted by some that debt issues for Canadian pipelines have traditionally been very attractive, in part because of the secure regulatory environment. The organizations consulted were generally of the view that a debt issue would be favourably received by the market.

With respect to attracting equity, some investment analysts noted that a major equity issue at the current ROE awarded by the NEB could be more problematic. They noted that recent projects, such as Alliance and M&NP, have been based on a higher equity return. It was noted by some that incumbent pipelines are at a disadvantage if they have to raise capital at the existing ROE. Others were of the view that greenfield projects are riskier and simply require a higher ROE to attract the equity investment. It was recognized that the Board has approved the higher ROEs that have been necessary to support greenfield pipelines such as Alliance and M&NP.

2.4.4 Other Comments by the Investment Community

Credit rating agencies and pension funds are primarily concerned about the predictability of cash flows to support debt and dividend payments. In this regard, the Board's RH-2-94 Formula is viewed positively because it improves predictability. Most of the companies with whom the Board met stated that they would like to see arrangements that provide certainty over multi-year periods because annual toll hearings introduce uncertainty and can distract pipeline management from focusing on other important aspects of their business. They also would like to see tolls and tariffs in place at the start of a fiscal year because interim toll situations increase uncertainty.

Pension fund administrators expressed the view that the Board should 'protect' credit ratings because downgrades could be very costly to bondholders. They noted that Canadian bonds are an important revenue source for Canadian pension funds and that a downgrade could require them to sell a large percentage of their bonds at discounted prices. On the other hand, some groups were of the view that the Board should not be overly concerned about maintaining a 'target' credit rating for a pipeline; investment grade ratings should be adequate.

It was noted by some that the business environment for the traditional Canadian gas pipelines has become somewhat riskier since the construction of the Alliance pipeline and the slowdown in the growth of gas production. Accordingly, they believe that basic financial parameters in the Board's regulatory scheme should be improved[8]. Finally, a number of parties expressed concern that the Board does not have adequate rules to ensure financial protection ('ring-fencing') of a regulated utility and concern was expressed that cash could be drained from a pipeline company if its parent were to experience severe financial difficulties.

2.4.5 Assessments by Equity Analysts

Several equity analysts regularly publish their assessments of various companies for investors. The Board reviews these assessments for the consolidated operations of pipeline companies as they provide some useful information on their financial viability and outlook for the future. As with credit ratings, equity analysts generally focus on companies that have stand-alone share offerings and, in many cases, these offerings include non-regulated as well as regulated businesses. While observations vary from analyst to analyst and from company to company, most NEB-regulated pipelines have been rated in the 'hold' or 'buy' categories over the last year, indicating that this sector of the investment community does not have any significant concerns about their short-term prospects.

8 In its RH-2-2004 Phase II Reasons for Decision dated April 2005, the Board approved an increase in TransCanada's deemed common equity ratio from 33 percent to 36 percent.

CONCLUSIONS AND EMERGING ISSUES

Conclusions

Based on the chosen measures, the Board believes that the Canadian hydrocarbon transportation system is working very well at the present time.

Currently, **there appears to be adequate natural gas pipeline capacity in place on existing systems**, especially since production from the WCSB has levelled off over the last few years. The existence of some excess capacity out of the WCSB has provided producers with the flexibility to access their market of choice and the value of natural gas exports hit a record high of $26.5 billion in 2004. There are some constraints in the system east of Dawn, Ontario but this has not to date caused any prolonged problems in delivering adequate volumes to the marketplace to meet the needs of consumers.

Overall, there is adequate capacity on the oil pipeline transportation system and all types of oil produced in the WCSB are being delivered to markets within and outside Canada. However, capacity on some systems has been tight, notably on Terasen (TMPL). This has been illustrated by the need for Terasen (TMPL) to apportion shippers in recent months and by Chevron's request for priority destination status for its Burnaby refinery. Canadian oil producers also appear to believe that there is a need to improve access to heavy crude oil markets in the U.S. Inadequate access to refineries designed to run heavier crudes appears to have been a contributing factor to the recent high heavy/light price differentials for Canadian crudes. This need for improved access has been illustrated by the Canadian industry's support for the reversal of two U.S. pipelines to Cushing, Oklahoma and the U.S. Gulf Coast to allow growing oil sands production to penetrate new markets.

Based on the results from the NEB Pipeline Services Survey, **shippers are reasonably satisfied with the services provided by pipelines** (overall rating of 3.78 out of 5). In particular, physical reliability of pipeline operations was rated very highly by shippers, indicating that products are reliably delivered to markets. There are, however, a few areas where some work is required on the part of the pipeline companies to improve service, including:

- making tolls more competitive;
- exhibiting an attitude of continuous improvement and innovation; and
- working collaboratively towards fair and reasonable solutions to resolve issues.

The financial assessment indicates that **NEB-regulated pipeline companies are financially sound**. However, it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies. While pipeline companies have not had to raise large amounts of capital in recent years, the Board's survey of the investment community revealed that it believes that

pipeline companies should have no difficulty in raising capital to finance most major new projects at this time.

The Board recognizes that this report is a snapshot in time and does not include a comparison, for example, with pipelines in other jurisdictions. The Board considers this report as a first step in assessing the effectiveness of the hydrocarbon transportation system in Canada. The Board will continue to monitor the effectiveness of the system and will continue to meet with parties to gain an understanding of all perspectives on the transportation system. The Board welcomes feedback at any time on the measures and conclusions in this report and welcomes suggestions for improvements to future reports.

Emerging Issues

While the transportation system is currently working well, there are a number of emerging challenges facing the industry.

To meet the needs of producers and users, the transportation system must be able to adapt to the changing needs of the market over time and expand to attach new sources of supply. This can be particularly challenging for the pipeline sector because investments tend to be "lumpy" and, given the long life of the assets, investors have to be reasonably assured of the existence of supply and markets over a long time period. Clearly, the longer the time period over which an investment is recovered, the greater the possibility that market circumstances will change.

The potential for market change over time is highlighted by the uncertainties around the number of liquefied natural gas (LNG) terminals that will be built in North America and the potential effects that imported LNG will have on the supply and demand balance and on the pattern of natural gas flows. For example, the construction of LNG terminals in Quebec could have important implications for the flow pattern on TransCanada and TQM and could impact the toll design of the system.

Another event that could impact the supply and demand balance and consequent gas flows is the significant potential gas requirement for power generation that will be driven by Ontario's policy to remove 7 500 MW of coal-fired capacity from its system. Although the refurbishment of existing nuclear generation might meet part of the requirement for the displaced coal, there will likely be a significant volume of new natural gas-fired generation to enter the system. The exact impact of this incremental generation on natural gas pipelines will depend on the total amount of generation awarded and the location.

On the oil side of the market, the expected growth in production from the oil sands is posing tough choices for the industry regarding which incremental markets to access and how to expand the pipeline system. Options include expansion of existing systems and construction of new systems to access new markets in either or both the U.S. and Asia. Given the large capital outlay and the relative irreversibility of the investment decision, market participants want to ensure that the optimal decisions will be made.

From a regulatory perspective, the challenge is to provide a fair and effective process that does not distort the investment decisions that should optimally be made in the marketplace. Investors in new pipelines desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. Unnecessary delays in construction of new systems that are in the public interest can result in increased costs to energy users as development of new supplies are constrained.

The flattening of natural gas production from the WCSB and construction of the Alliance pipeline has created challenges for a number of the older systems that are experiencing a sharp decline in the long-term contracts on their systems. Natural gas is still being moved on these systems, but many shippers prefer to rely on short-term services to maximize their flexibility. Under the traditional cost of service approach, the remaining firm shippers have to bear the load of recovering the fixed costs in the form of rising tolls. While the erosion of long-term contracts has not yet vitiated the cost of service framework, new toll design structures may need to be considered to effect a fair sharing of costs and to maintain the competitiveness of these systems.

Lastly, having regard to the financial viability of the pipeline companies, there is interest in the investment community and amongst shippers in working towards multi-year frameworks for the establishment of tolls on more pipeline systems. A multi-year framework would provide more certainty for all parties and reduce the burden associated with continual negotiations and regulatory proceedings. While the Board is committed to working towards a framework which reduces regulatory uncertainty, it recognizes that it may be difficult to structure a multi-year framework that will meet the needs of all parties when the market context is expected to change considerably in the next few years. The investment community would also like to see tighter regulatory rules regarding parent-affiliate dealings in order to protect the cash flows of the regulated entities.

Some of these issues will be settled amongst parties, others may be examined in formal proceedings before the Board, and others may be amenable to potential regulatory actions outside of the hearing process. The Board will continue to consult with stakeholders on these issues and seek input if and when any regulatory initiatives are pursued.

DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by DBRS and S&P when rating long-term debt.

Credit Quality	DBRS	S&P
Superior	AAA	AAA
	AA high	AA+
	AA	AA
	AA low	AA-
Good	A high	A+
	A	A
	A low	A-
Adequate	BBB high	BBB+
	BBB	BBB
	BBB low	BBB-
Speculative	BB high	BB+
	BB	BB
	BB low	BB-
Highly Speculative	B high	B+
	B	B
	B low	B-
	CCC	CCC
	CC	CC

Ratings in the Adequate category and above are considered Investment Grade.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

PIPELINE SERVICES SURVEY AGGREGATE RESULTS

The results below are the aggregate responses from shippers on several major NEB-regulated pipeline companies. See the Board's Web site for the complete details.

1. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
2	10	31	56	29	3.78

2. What are the things that this pipeline company does well?
3. What are the things that this pipeline company could do better?
4. How satisfied are you with the physical reliability of the pipeline company's operations?

1	2	3	4	5	Average
2	9	12	53	52	4.13

5. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc.)?

1	2	3	4	5	Average
5	9	32	51	27	3.69

6. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

1	2	3	4	5	Average
3	9	19	49	38	3.93

7. How satisfied are you with the timeliness and usefulness of *operations* information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the pipeline company?

1	2	3	4	5	Average
5	9	24	61	26	3.75

8. How satisfied are you with the timeliness and usefulness of *commercial* information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

1	2	3	4	5	Average
1	11	34	65	16	3.66

9. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
8	21	46	38	11	3.19

10. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
6	19	28	51	18	3.46

11. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	24	32	42	12	3.26

12. How satisfied are you with the suite of service options (FT, IT, backhaul, etc.) offered by the pipeline company?

1	2	3	4	5	Average
3	6	33	47	15	3.63

13. How satisfied are you that this pipeline company's transportation tolls are competitive?

1	2	3	4	5	Average
9	14	55	39	4	3.12

14. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
6	8	47	45	7	3.35

15. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
7	9	43	49	9	3.38

16. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
5	7	35	51	16	3.58

17. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
4	11	33	38	13	3.46

18. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

19. Additional comments

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CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

JUNE 2006

Canada

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National Energy Board

Office national de l'énergie

CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

JUNE 2006

Canada

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ACRONYMS AND ABREVIATIONS

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
Altex	Altex Energy Ltd.
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
Cochin	Cochin Pipe Lines Ltd.
Coral	Coral Energy Canada Inc.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
Foothills	Foothills Pipe Lines Ltd.
FT	Firm Transportation
FT-RAM	Firm Transportation Risk Alleviation Mechanism
GDP	Gross Domestic Product
Gateway	Gateway Pipeline Inc.
IGUA	Industrial Gas Users Association
Irving/Repsol	Irving Oil Company Limited and Repsol YPF
Kinder Morgan	Kinder Morgan Canada Inc.
LNG	Liquefied natural gas
M&NP	Maritimes & Northeast Pipeline Management Ltd.
Mackenzie	Mackenzie Gas Project

Moody's	Moody's Canada Inc.
NEB or Board	National Energy Board
OEB	Ontario Energy Board
PADD	Petroleum Administration Defense Districts
PCOG	Petro-Canada Oil and Gas
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Common Equity
S&P	Standard & Poor's
Terasen	Terasen Pipelines Inc.
T-South	Westcoast's Southern Mainline (Zone 4)
TNPI or Trans-Northern	Trans-Northern Pipeline Inc.
TPTM	Terasen Pipelines (Trans Mountain) Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
Union Gas	Union Gas Limited
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

UNITS

Bcf	Billion cubic feet
MMcf/d	Million cubic feet per day
GJ	Gigajoule
m^3/d	Cubic metres per day
$10^3m^3/d$	Thousand cubic metres per day
MW	Megawatt

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas. In addition, the Board provides energy information and advice by collecting and analyzing information about Canadian energy markets through regulatory processes and monitoring.

This report, the second of its kind, provides an assessment of the Canadian hydrocarbon transportation system. To do so, it brings together data from various publicly available sources that was collected and monitored by NEB staff as well as throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets and emerging issues. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA) and the Canadian Association of Petroleum Producers (CAPP) for comment. Comments provided by CAPP and CEPA were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: http://www.neb-one.gc.ca.

[1] The Canadian public interest is all Canadians and refers to a balance of economic, environmental and social interests that change as society's values and preferences change.

INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver this energy in the form of natural gas, natural gas liquids (NGLs), crude oil and petroleum products is critical to Canada's economic well-being.

Canadians depend on a safe, reliable and efficient energy supply. The 45 000 kilometres (km) of interprovincial and international pipelines regulated by the NEB are a crucial element in Canada's transportation and distribution system (Figures 1 and 2). These systems include large-diameter, cross-country, high-pressure natural gas pipelines, low-pressure crude oil and oil products pipelines, and small-diameter pipelines.

Pipelines have a well-deserved reputation as the safest and most energy-efficient method of moving vast amounts of fuel from producers to consumers. In 2005, approximately $120 billion worth of products flowed through Canadian pipelines to markets at home and in the U.S. The cost in 2005 of providing these transportation services is estimated to be around $5 billion, not including fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates with a low rate of failure and minimal environmental impact.

To assist in the delivery of its mandate and to ensure that the Board's regulatory oversight provides value to Canadians, the Board developed five goals:

1. NEB-regulated facilities and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built and operated in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective processes.

Each year, the Board issues various reports that focus on different aspects of Canadian energy markets. This report, which assesses how well the Canadian hydrocarbon transportation system is working, pertains largely to Goal 3. However, for the system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. Outcomes related to safety and the environment are discussed in a companion document, the Board's report, *Focus on Safety and Environment, a Comparative Analysis of Pipeline Performance.*

This report should not be read as a regulatory document. In this report, the Board is not making a determination on regulatory matters because the factors on which the functioning of the transportation system is assessed are not necessarily the same as those considered in a regulatory proceeding.

For the hydrocarbon transportation system to work well, the Board believes the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move energy products from producers to consumers;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial integrity to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

An efficient hydrocarbon transportation system needs to have the ability to be expanded on a timely basis when changing market conditions require new pipeline capacity. In order for expansion to occur in the time frame required, two things should occur. First, pipeline companies must have ready access to financial markets on reasonable terms and conditions. In addition, the regulatory process must be timely and predictable, while allowing a fair opportunity for all affected parties to provide input prior to a decision on an application being made.

In this report, the Board provides an assessment of the ability of pipeline companies to access capital on reasonable terms and conditions. The Board does not, however, provide an assessment of the efficiency and effectiveness of its regulatory processes. The Board reports on a number of regulatory efficiency measures in its *Annual Report to Parliament* and in the annual *Departmental Performance Report* that are submitted to the Treasury Board, both of which are public documents. This report, in the discussion of the Pipeline Services Survey (see Section 2.3.1), does provide information on shippers' perceptions of the Board's regulatory process. The Board recognizes that there is the potential to improve the means by which regulatory effectiveness and efficiency is measured and will be consulting with stakeholders on this topic.

For the Board's financial regulatory purposes, pipeline companies have been divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are actively regulated by the NEB. All other NEB-regulated pipeline companies are classified as Group 2 companies and are subject to a lighter degree of regulation. A listing of companies regulated by the Board, as of 31 December 2005, can be found in Appendix 4.

FIGURE 1

Gas Pipelines Regulated by the NEB

FIGURE 2

Oil Pipelines Regulated by the NEB

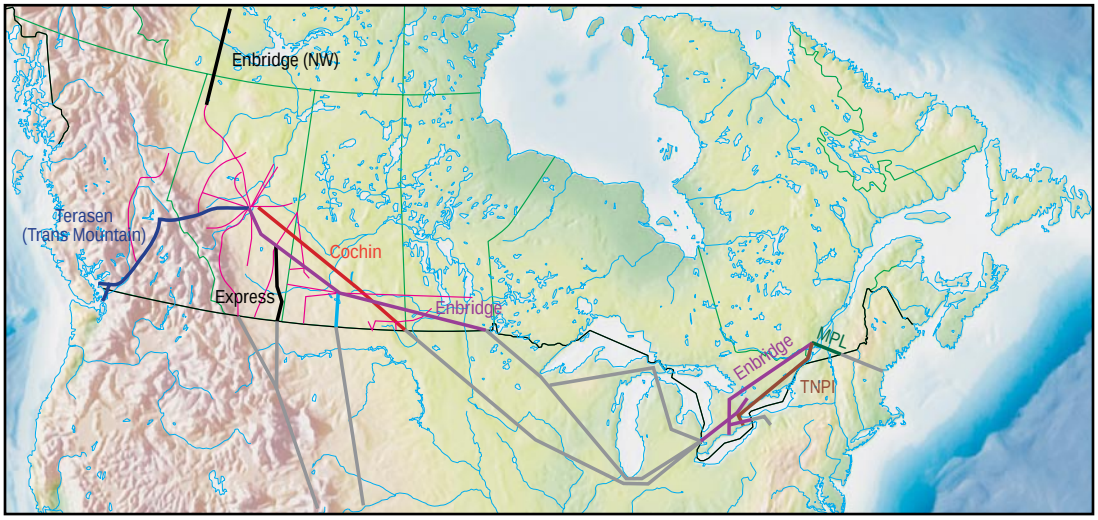
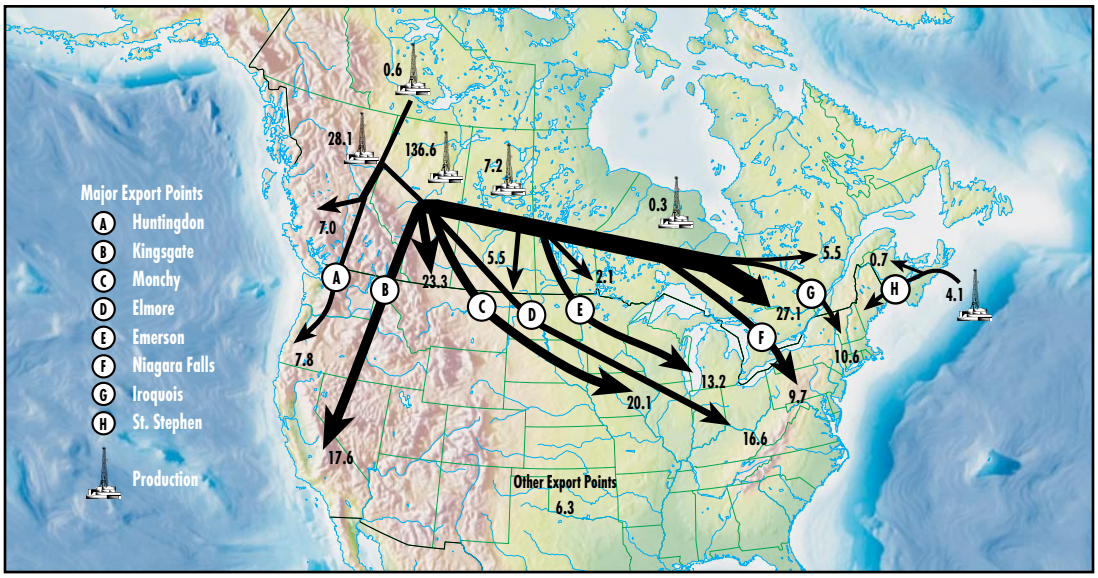


FIGURE 3

2005 Supply and Disposition of Natural Gas

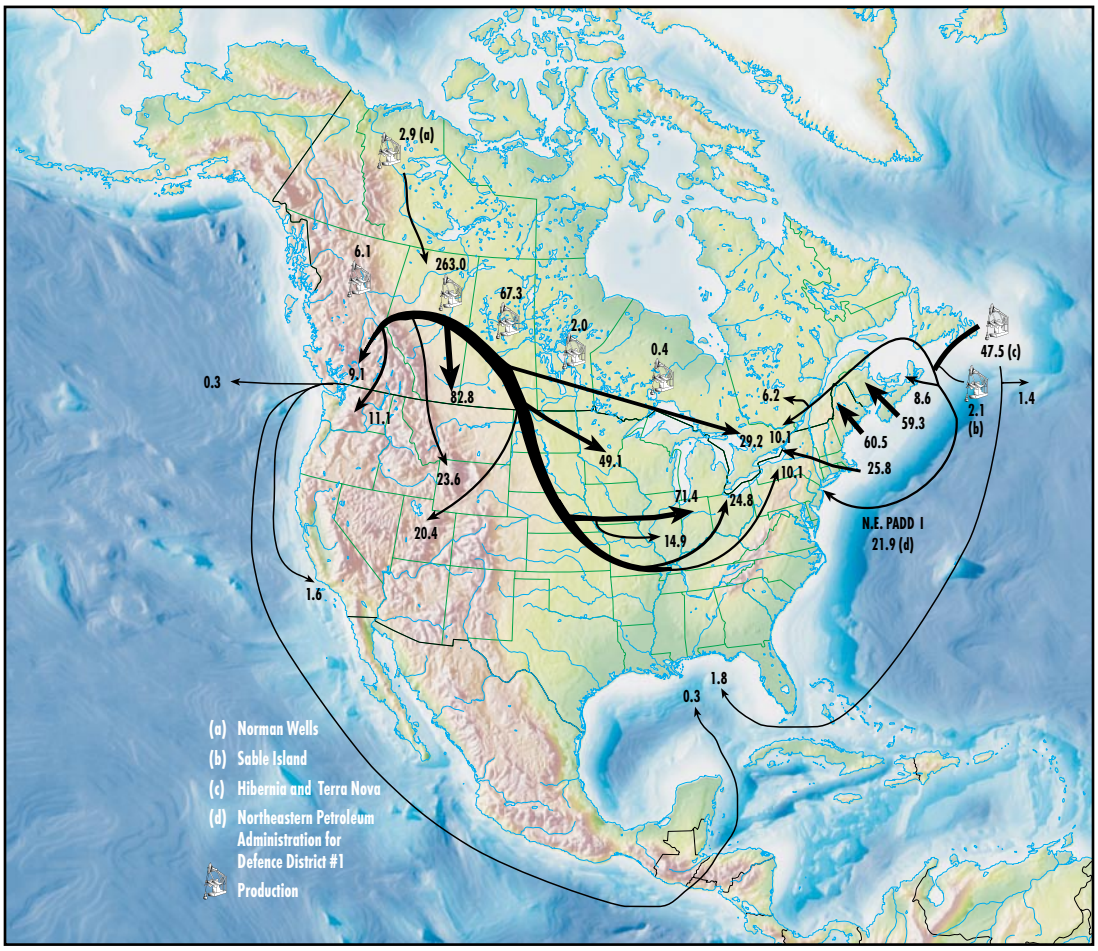


Publicly available data for Group 1 companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company, was used to assess the extent to which the three outcomes identified by the Board are being achieved. These companies represent ownership of the majority of the Canadian hydrocarbon transportation system regulated by the NEB and the data from these companies provides a good view of the overall functioning of the hydrocarbon transportation system.

More detailed information can be found in the Board's 2005 Annual Report.

FIGURE 4

2005 Supply and Disposition of Oil



THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

2.1 Adequacy of Pipeline Capacity

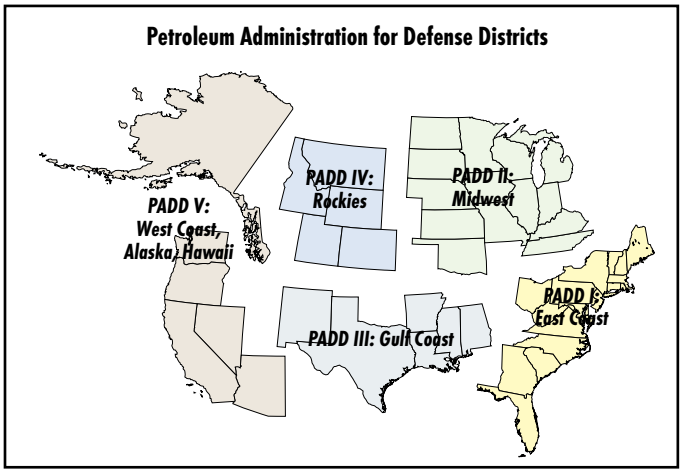
A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and NGLs from producing to consuming regions.

This section examines the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is better than not having enough. Higher tolls for shippers are a cost of having excess pipeline capacity; however, the costs associated with not having enough pipeline capacity are generally greater. Substantial revenue is lost when producers are unable to move their oil or gas to market. Not only is it important to have some excess capacity, but flexibility with sufficient access to the right markets or for the right type of product is also important.

When there is inadequate pipeline capacity to transport crude oil to the West Coast and PADD V (West Coast) producers have the option of transporting crude oil to Ontario and PADD II (Midwest) or PADD IV(Rockies). In addition, when refineries are in turnaround (maintenance) in Ontario and PADD II, crude oil volumes can be delivered to the West Coast and PADD V or PADD IV providing there is pipeline capacity.



The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines.

2.1.1 Price Differentials and Natural Gas Firm Service Tolls

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. Conversely, when there is inadequate pipeline capacity between two market points, the basis, that is the differential in price between the two end points, will exceed the cost of transportation. In a market with adequate capacity, sellers would generally direct their product to the market that nets the highest revenue back to the producer, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use price differentials as a measure of the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission (Westcoast).

Figure 5 shows the basis differential between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The basis between the Alberta border and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in basis between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. The short-term increase in the basis differential between September 2005 and January 2006 was a result of increased demand for supply from other basins when gas supplies from the Gulf of Mexico were reduced due to hurricanes Katrina and Rita. Cold weather early in the winter also affected demand. In addition, after the hurricane-induced gas price increase, the cost of fuel for use in the pipeline compressors also increased temporarily. Very mild weather and reduced demand in response to higher prices has since moderated flows and the demand for gas and transportation.

FIGURE 5

Dawn – Alberta Basis vs. TransCanada Toll and Fuel

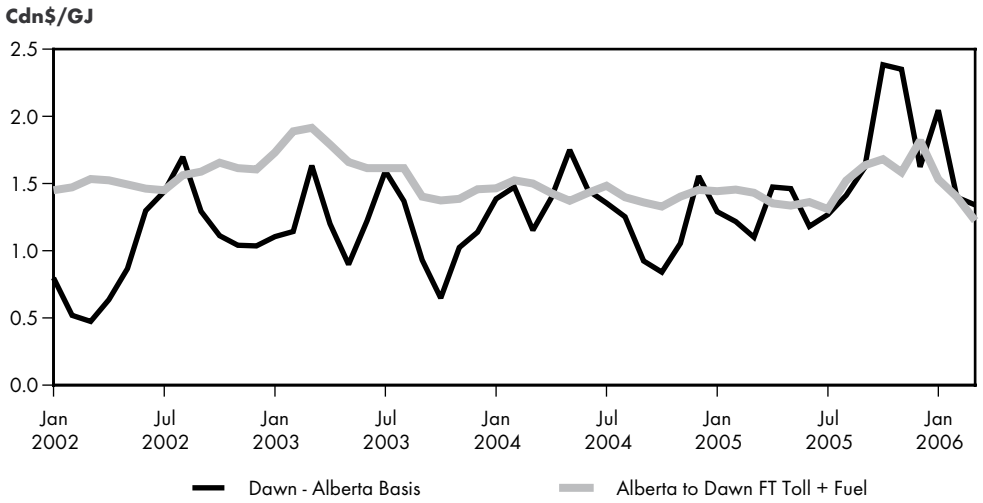
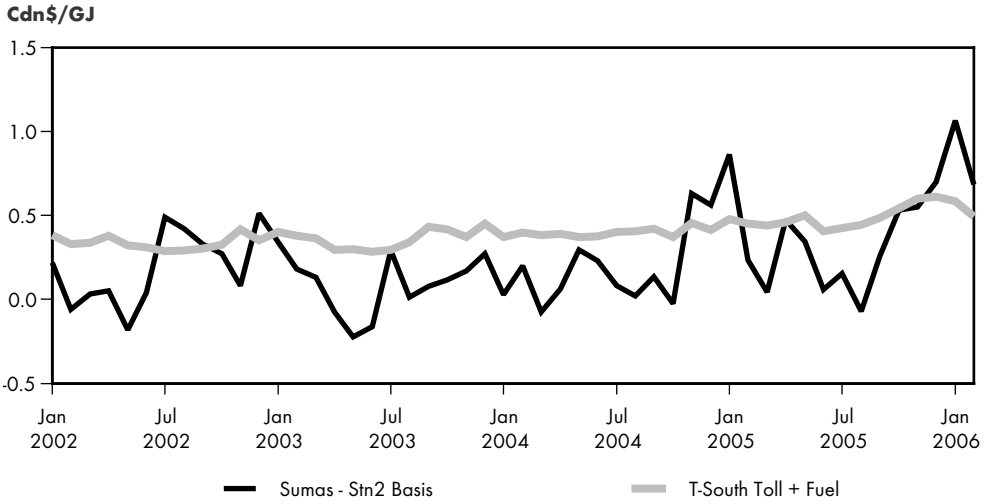


Figure 6 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Since January 2002, except for a few months, the basis has been lower than the transportation costs indicating that there has been adequate capacity in place since that time.

FIGURE 6

Sumas – Station 2 Basis vs. Westcoast T-South Toll and Fuel



Note: 2006 - interim term-differentiated toll (5 or more years service).

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the basis between pricing points has been slightly lower than pipeline transportation and fuel costs. However, natural gas pricing is volatile. Hurricane-induced supply disruptions in the Gulf of Mexico and erratic weather impact both basis and pipeline fuel costs. Figures 5 and 6 both indicate times where the basis exceeded transportation and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

Price Differentials and Tolls on Oil Pipelines

The major drivers of price differentials, amongst other things, are availability of pipeline capacity, competition, supply and demand, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of the increase in bitumen blend crude oil supply from the oil sands. Limited access to markets, particularly those with refineries that process heavy crude oil, exerts downward pressure on heavy oil prices and widens the light-heavy differential.

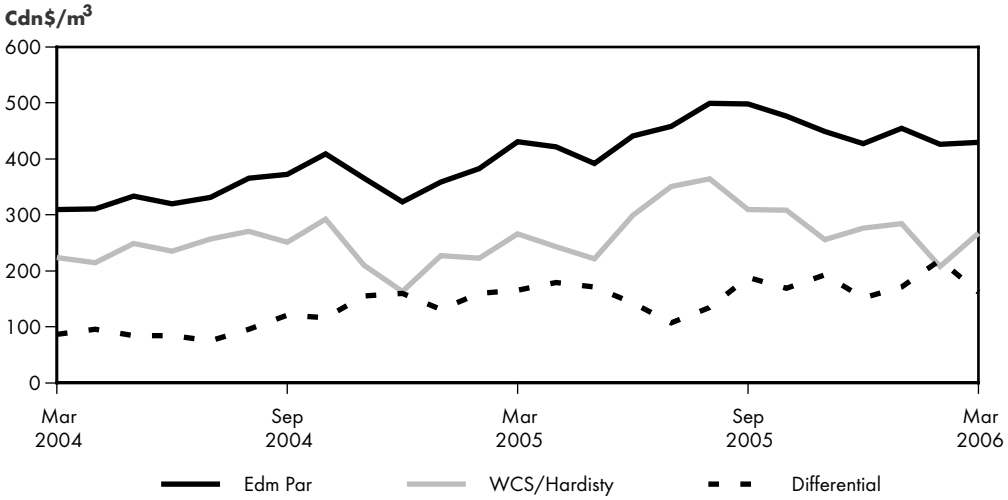
Figure 7 illustrates the wide light-heavy differential as indicated by the difference in price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil. As shown, the average differential has been increasing during the time period shown and in recent years has averaged about 30 percent over the course of a year. Notably, in the first quarter of 2006, the price of heavy crude was, on average, 42 percent less than the price for light crude oil (the light-heavy differential).

Typically, the differential is narrower during the summer months due to the additional demand for heavier crude oil for use in the production of asphalt for paving.

Differentials have also widened as a result of supply growth from the oil sands, pipeline constraints and a lack of refinery capacity to process heavier crude oil. Wide light-heavy differentials reduce heavy oil producers' netbacks and at extreme levels could possibly result in some oil sands projects being uneconomic. Recently, the differential has narrowed because of increased market access with the delivery of western Canadian crude oil to Cushing, Oklahoma through the Spearhead Pipeline and into the U.S. Gulf Coast through the reversed Mobil Pipeline.

FIGURE 7

Canadian Crude Oil Prices and Differential



2.1.2 Capacity Utilization on Major Routes

Pricing data is available for a number of injection and delivery points on pipeline systems. Even where this data is not available, another measure of adequate capacity is obtained by comparing throughput with capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

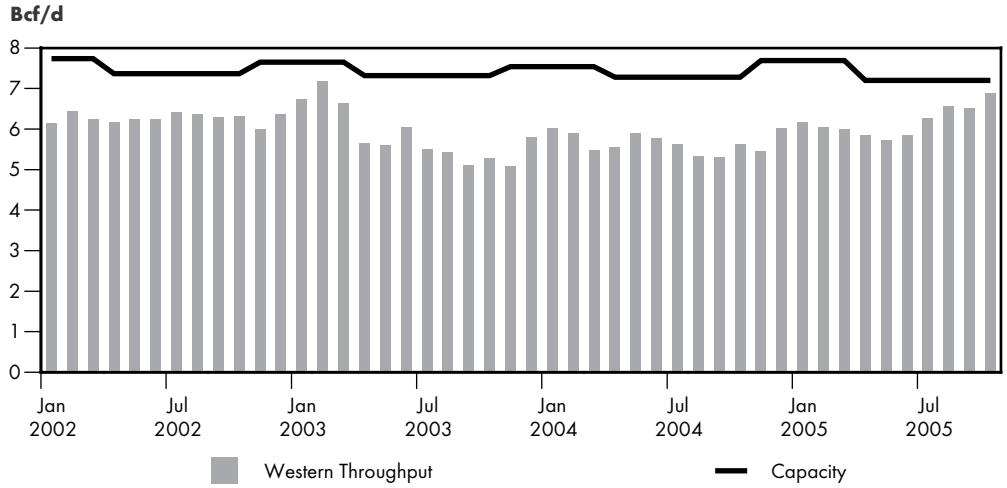
The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

Natural Gas

Figure 8 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. It demonstrates that while the prairie line has been operating at between 70 to 80 percent of capacity since April 2003, the volumes have increased in recent months. These higher volumes reflect increased eastern demand for Canadian gas due to last year's hot summer weather and reduced gas supplies (since September) from the Gulf of Mexico following the late summer hurricanes. Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets.

FIGURE 8

TransCanada Mainline Throughput vs. Capacity



The volumes shown in Figure 9 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline connects with Northern Border Pipeline Ltd. (Northern Border) and Monchy, Saskatchewan to flow gas to the U.S. Midwest. While the Foothills (Sask.) capacity utilization has been running at an annual average of about 94 percent since 2002, there was some decline in the spring of 2005. The lower volumes were due to a period of unsold firm capacity on the connecting Northern Border pipeline, stemming from low seasonal demand and high storage levels.

FIGURE 9

Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy

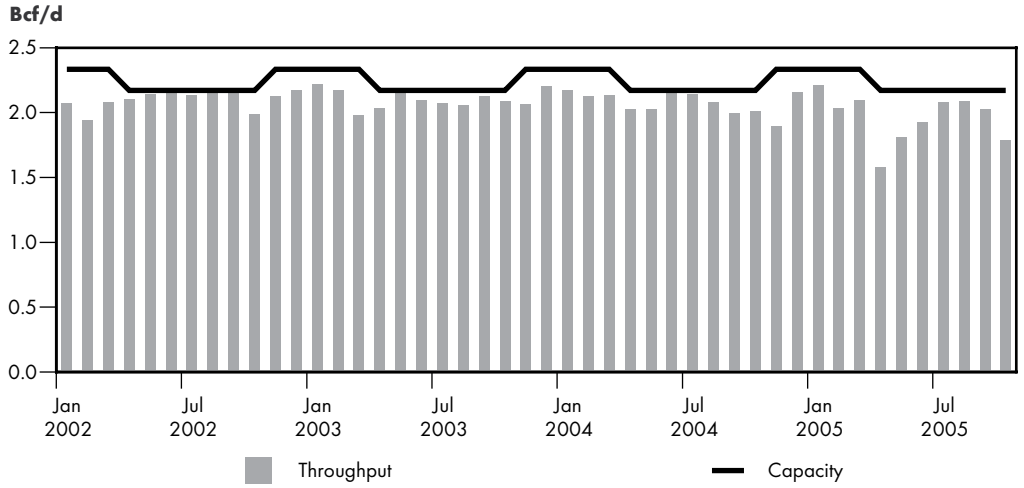


Figure 10 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. One of the major contributors to low flows on Westcoast is the competition with production from the U.S. Rockies region which also has access to the U.S. Pacific Northwest market via Williams' Northwest Pipeline system. A warm winter and increased hydro power generation in British Columbia and the U.S. Pacific Northwest reduced gas flows on this pipeline in early 2006. In fact, the peak flow levels were lower than normal, as was the duration of the winter peak.

FIGURE 10

Westcoast Mainline Throughput vs. Capacity

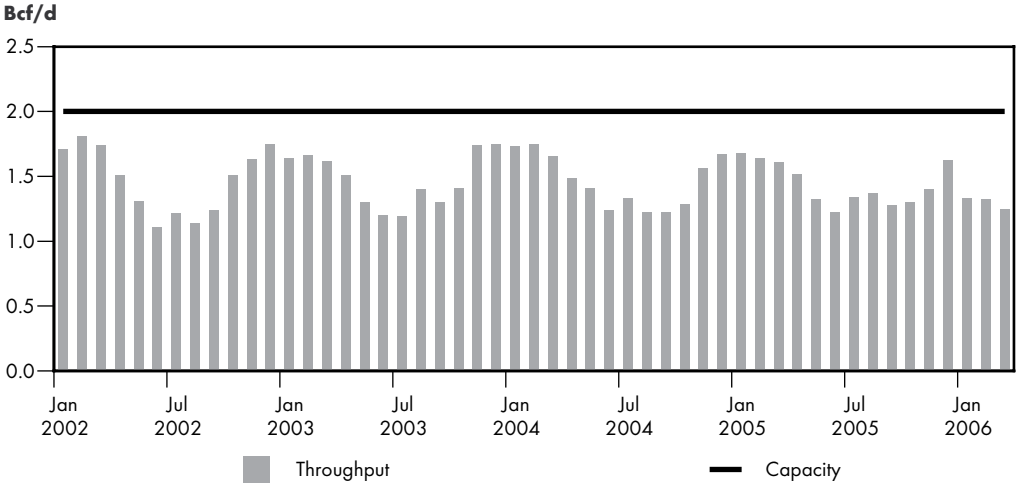


Figure 11 shows the average monthly throughput and capacity on the TransCanada B.C. System. The annual average capacity utilization dropped from about 77 percent in February 2002 to about 60 percent in March 2006, and there is spare capacity on this pipeline to export gas through Kingsgate. In California, which is the B.C. System's primary market region, market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB).

FIGURE 11

TransCanada B.C. System Throughput vs. Capacity at Kingsgate

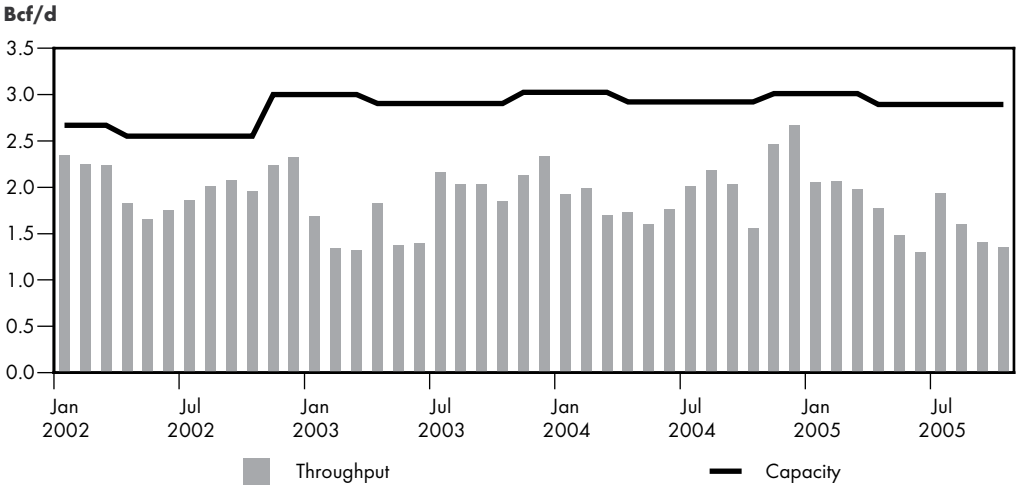


Figure 12 shows the average monthly throughput on the Alliance system relative to physically available capacity levels. Alliance offers approximately 37 534 $10^3m^3/d$ (1.325 Bcf/d) of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

FIGURE 12

Alliance Throughput vs. Capacity

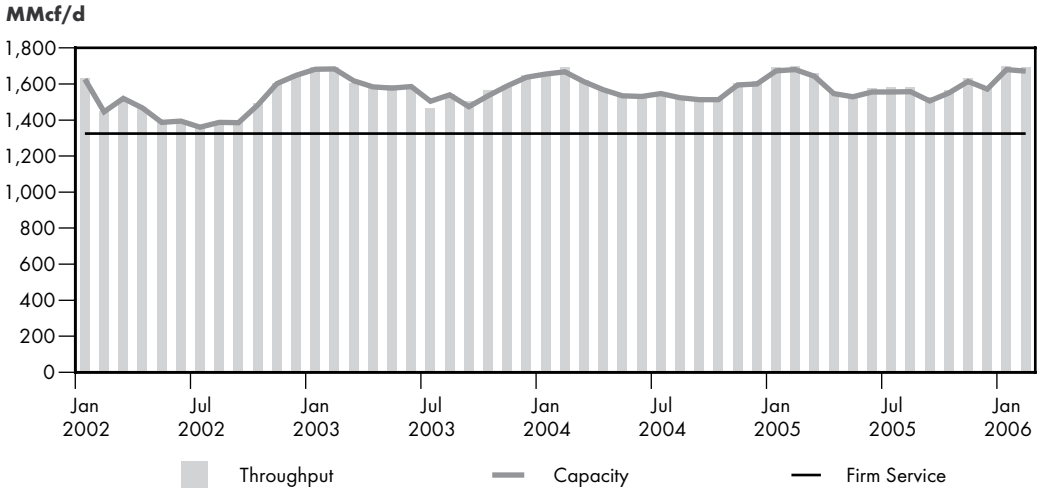


Figure 13 compares the average monthly throughput and capacity on TQM. This figure shows the seasonal nature of the throughput on this pipeline, with more volumes being transported during the peak winter months. With the annual average capacity utilization of around 60 percent, there is spare capacity on this pipeline which delivers gas between the TransCanada Mainline, connecting TQM at Saint-Lazare on the Ontario and Québec border, and TQM's endpoints at Saint-Nicolas (south shore of Québec City) and East Hereford (New Hampshire state border). However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution along the pipeline. Higher system utilization in 2005 reflects increased exports at East Hereford due to reduced gas supplies from the Gulf of Mexico following the late summer hurricanes.

FIGURE 13

Trans Québec & Maritimes Throughput vs. Capacity

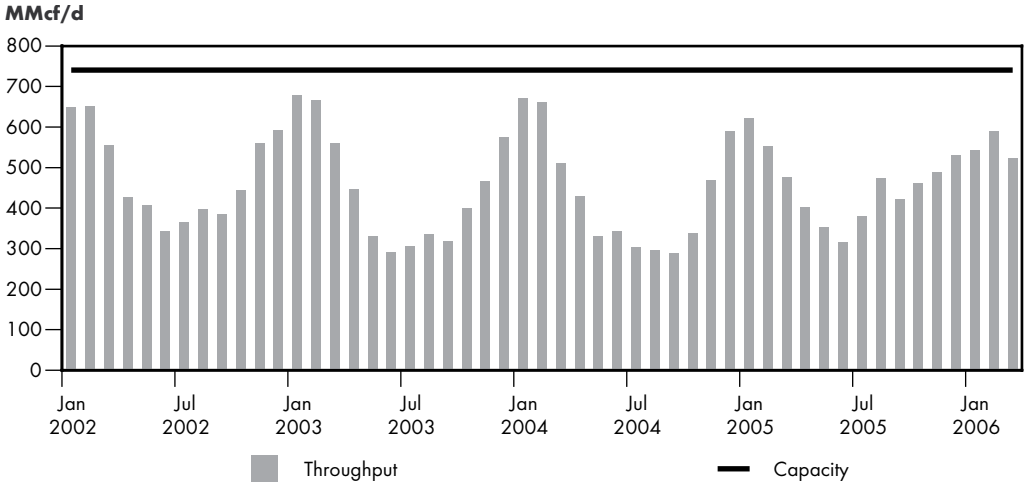
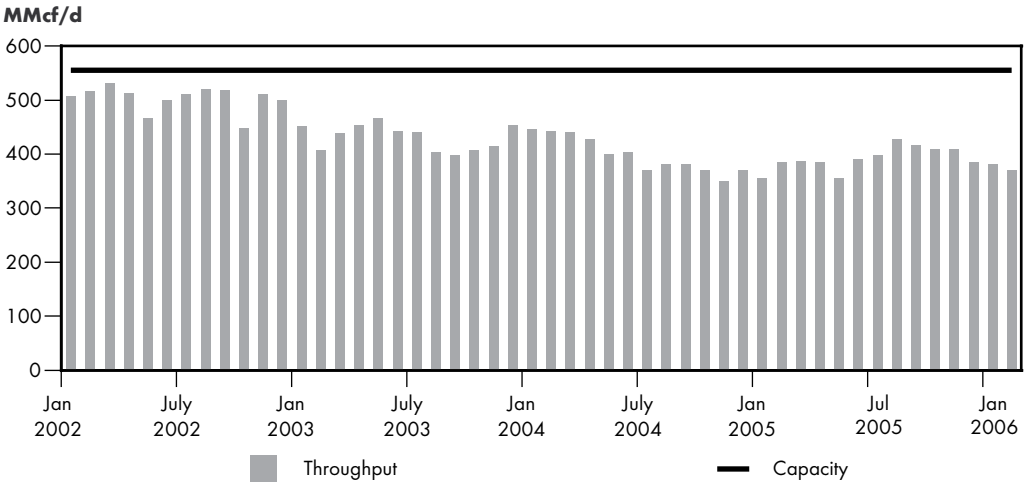


Figure 14 compares the average monthly throughput on the M&NP pipeline with its capacity. The annual average capacity utilization has been declining from about 92 percent in 2002 to an average of about 70 percent in 2005. The drop in this pipeline's utilization stems from declining natural gas production from Nova Scotia's Sable Offshore Energy Project. The variations in throughput are primarily related to changes in gas supply.

FIGURE 14

Maritimes & Northeast Pipeline Throughput vs. Capacity



Although the Dawn-Parkway corridor is not regulated by the NEB, it is a key link between the Dawn hub and growing markets in eastern Canada and the U.S. Northwest. Last year the Ontario Energy Board (OEB) approved Union Gas' Phase 1 Expansion, expected to be in service by November 2006. This year, Union filed an application with the OEB for its Phase 2 Expansion. If approved, the expansion is expected to be in service by 1 November 2007. Market demand for capacity in this corridor is expected to remain robust due to the liquidity of Dawn as a transactional trading point given its market reach.

Oil

Determining the capacity and throughputs on an oil pipeline can be complex as there are a number of factors to be considered: the type of product, product mix, type of batching, pipeline configurations and bottlenecks.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba to join the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The system consists of several lines transporting crude oil, NGLs and refined petroleum products. Figure 15 illustrates Enbridge Mainline throughput versus capacity for all lines. In 2005, Enbridge transported roughly 224 600 m^3/d (1.4 million barrels per day) of crude oil, petroleum products and NGLs. In the first quarter of 2006, Enbridge operated at around 80 percent of capacity (Figure 15). Certain lines, particularly Lines 3 and 4, which transport heavy oil, have been operating at or close to full capacity, with some apportionment (see Section 2.1.3).

In November 2005, Kinder Morgan purchased Terasen Inc., owner of the Trans Mountain pipeline system. This purchase made Kinder Morgan a major oil pipeline player in Canada. TPTM's current capacity, assuming some shipments of heavy oil, is 35 700 m^3/d (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (see Section 2.1.3). However, the capacity indicated in Figure 16 is 45 300 m^3/d (285 Mb/d). This higher capacity assumes no heavy crude oil shipments. On average, particularly in the last two years, 20 percent of TPTM's crude oil receipts at Edmonton are heavy and because of the increased viscosity, pipeline capacity was reduced to 35 700 m^3/d (225 Mb/d).

FIGURE 15

Enbridge Pipeline Throughput vs. Capacity

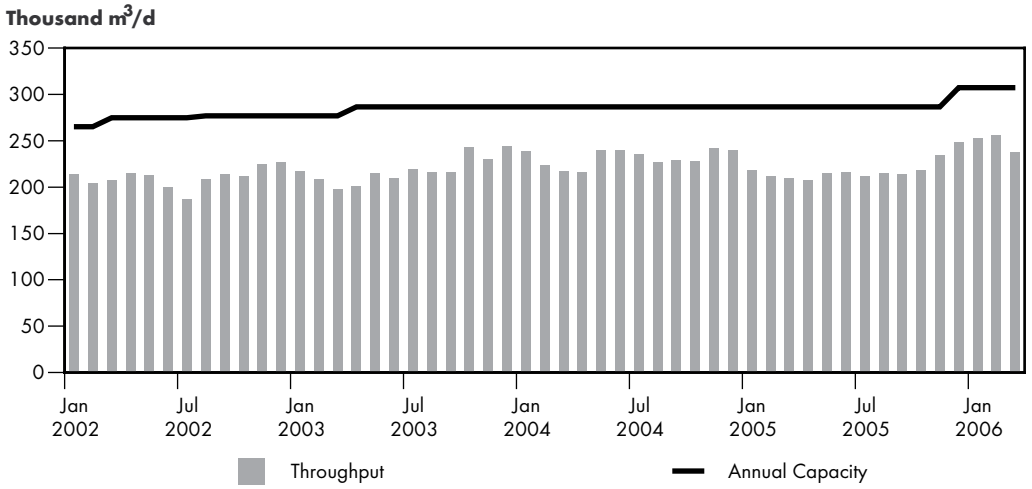
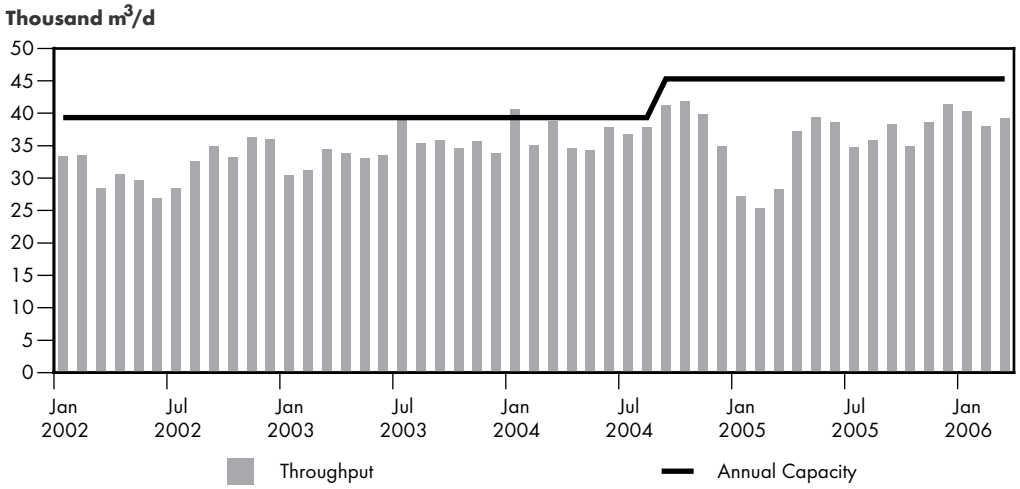


FIGURE 16

TPTM Throughput vs. Capacity[2]



On 5 July 2005, Terasen applied to the NEB for a capacity increase of 5 600 m^3/d (35 Mb/d). It was approved on 10 November 2005 and the in-service date is April 2007.

In the first quarter of 2006, TPTM operated at approximately 86 percent of capacity (see Figure 16). Though the system did not operate at capacity, TPTM was under apportionment in January, February and March of 2006. Many factors contributed to this apportionment, including growing oil sands supply coupled with increased demand from Washington State refiners and crude oil shipments off the Westridge Dock.

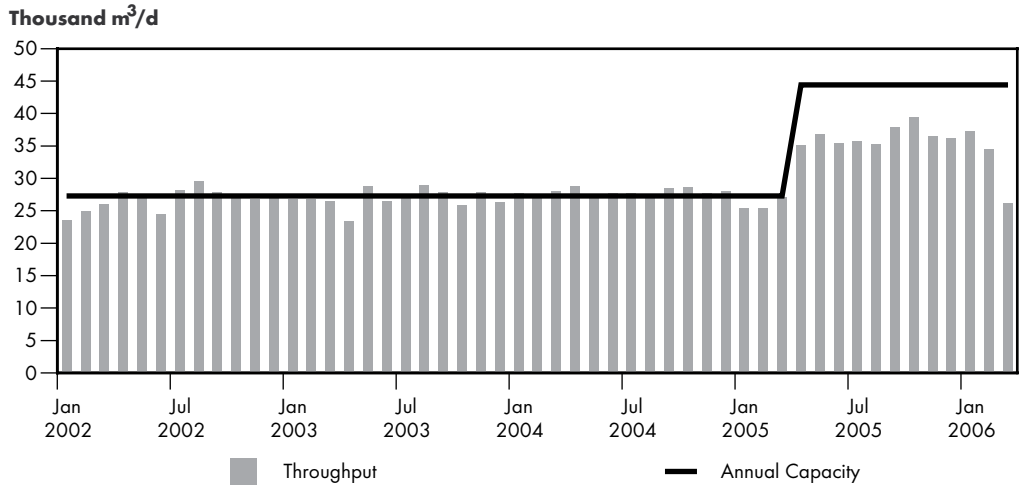
During the past several years, Express has been operating at capacity. In April 2005, Express completed its 17 600 m^3/d (100 Mb/d) expansion, bringing the total capacity to 44 900 m^3/d (280 Mb/d). Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for the majority of its capacity.

2 Capacity shown is light crude oil only (0% heavy).

In the first quarter of 2006, Express operated at approximately 73 percent of capacity (Figure 17). Throughputs were reduced in March 2006 due to apportionment on the Platte Pipeline system in the U.S.

FIGURE 17

Express Throughput vs. Capacity



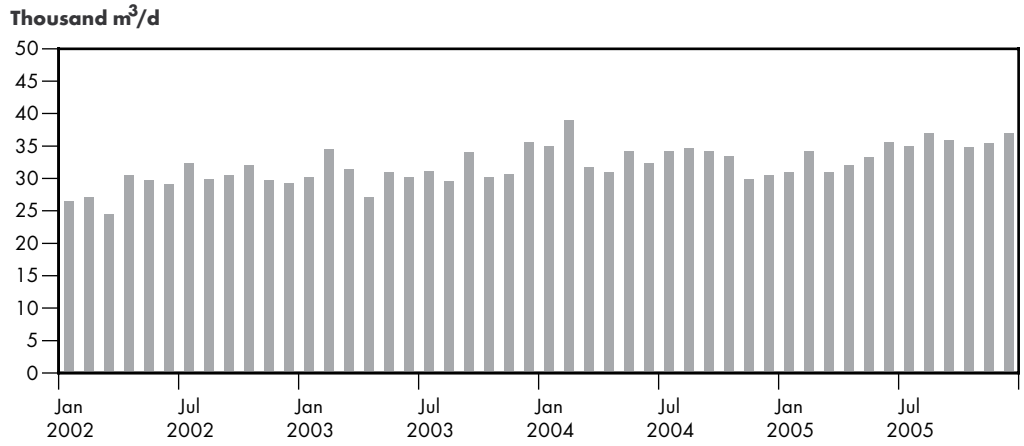
TNPI is a refined petroleum products pipeline. Historically, the pipeline system extended from Nanticoke, Ontario to Montreal, Quebec serving petroleum industry terminals along the route. In 2003, TNPI applied to the Board to increase the line capacity between Montreal and Farran's Point, Ontario from 10 500 m^3/d (66 150 Mb/d) to 21 000 m^3/d (132 300 Mb/d) and to reverse the direction of flow between Farran's Point and Metropolitan Toronto from a west-to-east direction to an east-to-west direction.

The Board approved TNPI's application to reverse the line and to accept take-or-pay obligations from Petro-Canada and Ultramar for 91 percent of the capacity. The remaining 900 m^3/d or nine percent of the capacity from Farran's Point to Toronto is available for spot shipments.

The expansion and the reversal, which took place in November 2004, were a response to declining shipments on the TNPI system and the closure of Petro-Canada's refinery in Oakville, Ontario. Increased deliveries from Montreal on TNPI serve markets in Ontario formerly served by Petro-Canada's Oakville refinery and by Ultramar by rail from Quebec (Figure 18).

FIGURE 18

Trans-Northern Pipelines Inc. Throughputs



Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

2.1.3 Apportionment

Oil pipelines normally operate as common carriers, although pipelines such as Express, Enbridge Line 9 and TNPI operate with long-term shipper take-or-pay agreements. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for the pipeline's capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff set out by the pipelines. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. Some recent apportionment data for Enbridge, TPTM and Cochin is shown below.

Enbridge

Historically, Lines 2 and 4 were dedicated to the transportation of heavy crude oil and Line 3 was dedicated to the transportation of light and medium crude oils. In the third quarter of 2005, Enbridge completed the Terrace Phase III expansion project to facilitate the growth in heavy crude oil. By converting Line 2 from heavy to light service and Line 3 from light to heavy service, it increased its heavy capacity by 39 000 m^3/d (245 700 b/d and reduced its light capacity by 18 400 m^3/d (115 920 b/d).

As illustrated in Table 1, Line 4 was under apportionment once between August 2005 and February 2006. In February, each shipper was required to reduce its volume, resulting in a three percent reduction. There are a number of factors that caused the apportionment: increased throughput from the oil sands, apportionment on the Platte system in the U.S., increases in conventional production in North Dakota for injection at Cromer, Manitoba and Clearbrook, Minnesota; pipeline reconfiguration; and refinery maintenance.

Enbridge's Line 9 has a capacity of 38 150 m^3/d (240 000 b/d) and transports oil from Montreal, Quebec to Sarnia, Ontario. In contrast to last year, there was no apportionment on the line between August 2005 and February 2006. This was partly due to increased volumes of western Canadian light conventional crude oil being processed in Ontario refineries.

TABLE 1

***Enbridge Appointment*[3]**

	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06
Line 4 Apportionment	0%	0%	0%	0%	0%	0%	3%
Throughput (10^3m^3/d)	104.3	103.4	102.4	113.0	90.4	113.9	111.0

Terasen Pipelines (TransMountain) Inc.

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment in November 2005 through to March 2006 reflects increased volumes associated with expansion in the oil sands and the higher market demand for Canadian crude. In addition, heavy crude oil volumes also increased during this time limiting capacity on the TPTM system. With improving market economics TPTM is delivering increasing volumes of western Canadian crude oil into Washington

State refineries as well as for export over the Westridge Dock which contributed to apportionment at both of these locations.

Following three notices of motion and an oral argument heard on 11 April 2006, the Board released its Decision approving the inclusion of a premium in the Tariff as a means of allocating capacity to the Westridge Dock. Further information can be found in the Board's letter decision dated 12 April 2006 and MH-2-2005.

TABLE 2

TPTM Apportionment

	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
Apportionment								
Domestic	0%	0%	0%	12%	0%	16%	32%	34%
Export	0%	0%	0%	18%	15%	18%	33%	43%
Dock	0%	0%	0%	74%	0%	30%	87%	93%
Throughput ($10^3m^3/d$)	35.9	38.4	34.9	38.7	41.4	40.3	38.0	39.2

Cochin

The Cochin pipeline is the largest and longest NGL pipeline in Canada. It transports propane, ethane, ethylene and butane, although no butane has been transported since 2002. Ongoing maintenance work on the pipeline has affected the available capacity. The lower throughput volumes and apportionment in September 2005 was caused by unexpected downtime required for immediate repairs. Because ethylene was already in the pipeline, there was no flexibility to transport larger volumes of other products (ethylene has a higher vapour pressure than propane and ethane and reduces the capacity of the pipeline).

Effective 7 March 2006, Cochin suspended the transportation of ethylene until at least the fall of 2007 due to a defect found in the U.S. portion of the pipeline and went on a voluntary pressure restriction. The pressure is not to exceed 900 psi and applies to the whole line from Fort Saskatchewan, Alberta to Windsor, Ontario. Without ethylene in the pipeline, propane and ethane shippers are not expected to face apportionment. The average capacity will be around 10.3 to 11.9 $10^3m^3/d$ (64 890 b/d to 79 970 b/d). Once the pressure restrictions are lifted, capacity is expected to return to 17.5 $10^3m^3/d$ (110 250 b/d).

TABLE 3

Cochin Apportionment

	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
Apportionment	0%	18%	0%	0%	0%	0%	0%	0%
Throughput ($10^3m^3/d$)	8.6	5.6	9.9	6.0	9.7	9.2	9.8	7.7

2.1.4 Summary of the Adequacy of Pipeline Capacity

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines shows that pipeline capacity is adequate across the country although there may be limitations at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas through some Canadian pipelines can be variable as well.

[3] Line 4 was the only line on the Enbridge system out of western Canada that was apportioned during this period.

Where possible, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently with higher annual capacity utilization.

Oil pipeline capacity, however, is tight and is expected to remain tight through 2008, even with the current expansions underway (Figure 28). This is being driven by increases in crude oil supply from the oil sands and in conventional production in North Dakota and PADD IV. In the first quarter of 2006, the price of heavy crude oil was, on average, 42 percent less than the price of light crude oil. This compares to a more typical light/heavy differential of around 30 percent. The light/heavy differential is typically wider during the winter months, reflecting reduced demand for asphalt and lower gasoline demand. However, the size of the differential in the first quarter reflects pressures building from an increase in supply, in this case from the oil sands, pipeline constraints and lack of refinery capacity to process heavier crude oil. Recently, the differential has narrowed as a result of market extension into Cushing, Oklahoma and the U.S. Gulf Coast through the Spearhead Pipeline and the Mobil Pipeline, respectively.

2.2 Pipeline Tolls

2.2.1 Pipeline Tolls Index

Another indicator of a hydrocarbon transportation system's efficiency is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). One of the factors the Board uses to analyze this is year-to-year variations in a benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost-of-service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase. The following sections review variations and trends of some NEB-regulated pipeline tolls since 1997.

Natural Gas Pipeline Tolls

The benchmark tolls[4] for TransCanada's Mainline, Westcoast, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator[5] normalized to the year 2001 are shown in Figure 19.

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 the toll fell, primarily due to increased contract demand and is below the level that it was in 2000.

Westcoast's tolls have increased moderately except for two years, 2000 and 2005. In 2000, Westcoast's benchmark toll increased more than 10 percent from the previous year primarily due to a large amount of non-routine pipeline integrity costs and in 2005, this toll increased by over 15 percent due to decontracting of firm services.

[4] The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

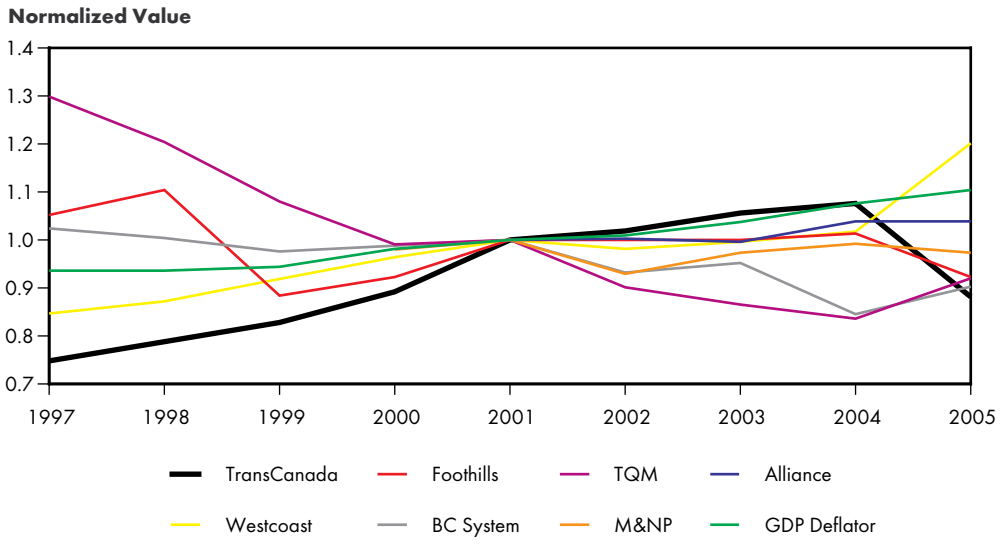
[5] The GDP deflator for 2005 is an estimate using actual data for the first half or the year and data estimated by Infometrica for the second half of the year.

The B.C. System, Foothills and TQM's benchmark tolls were lower in 2005 than in 1997. The B.C. System's benchmark toll decreased in 2004 primarily because of an increase in throughput volumes (over 10 percent) from 2003. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system. TQM's benchmark toll has decreased since 1997, although it increased somewhat in 2005. The decline was due, in part, to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998.

M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

FIGURE 19

NEB-Regulated Gas Pipeline Benchmark Tolls



Oil Pipeline Tolls

The benchmark tolls for Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2001[6], are shown in Figure 20.

Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2002. The tolls increased the most in 2000 and 2004. The increase in 2000 was due to unforeseen lower throughput levels in the previous year. Under its negotiated settlement, Enbridge was able, in the following year, to recapture the revenue shortfall due to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization as a result of throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last two years. There was a large increase in 1999 due to low forecast throughput. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which lead to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped primarily due to the disposition of 2003 deferrals for higher revenue. TNPI and Express's benchmark tolls moved in line with the GDP deflator from 1997 to 2005.

6 The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

FIGURE 20

NEB-Regulated Oil Pipeline Benchmark Tolls

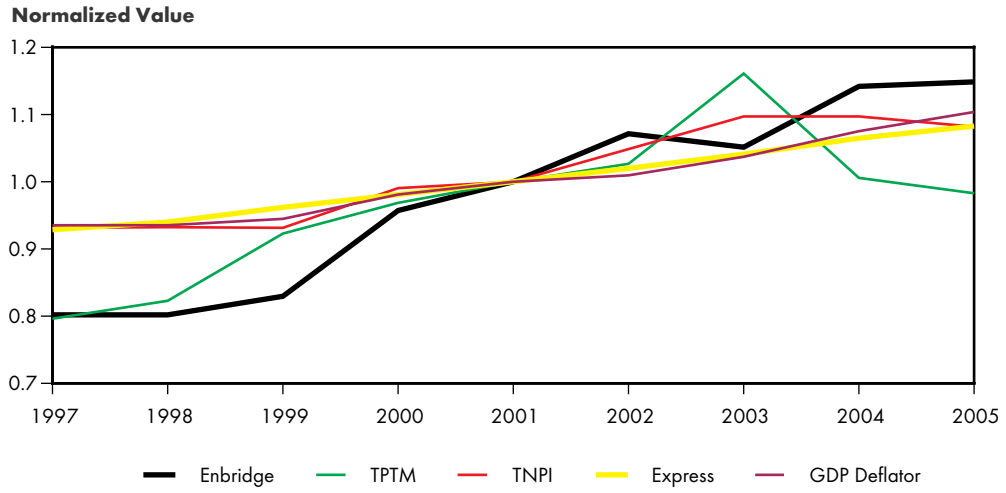
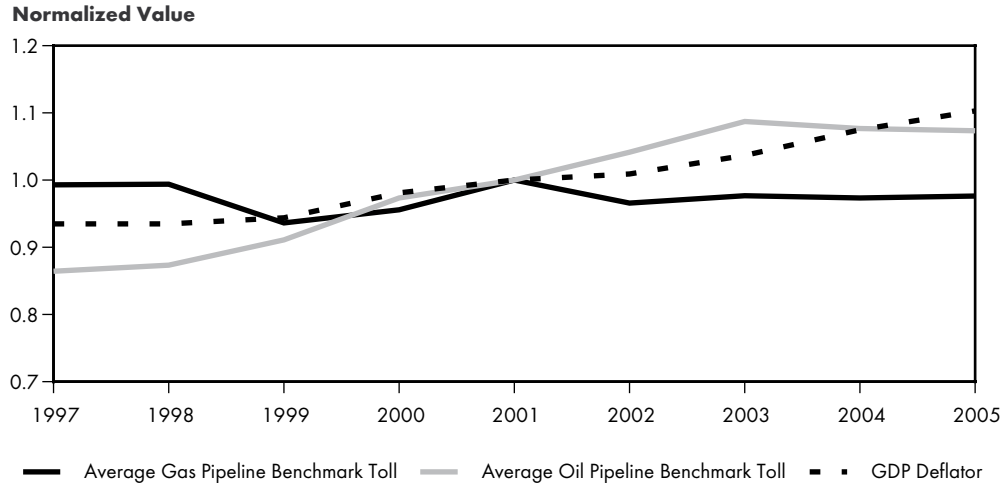


FIGURE 21

Oil and Gas Pipeline Benchmark Tolls



Comparison of Gas and Oil Pipeline Tolls

The average gas and oil benchmark pipeline tolls (reported in Figures 19 and 20) and the GDP deflator are graphed in Figure 21. From 1997 to 2005, oil pipeline tolls increased on average more than gas pipeline tolls, whereas gas pipeline tolls experienced more variation than oil pipeline tolls.

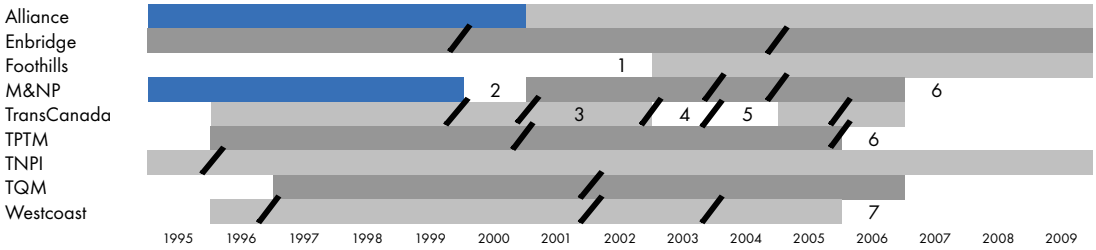
2.2.2 Negotiated Settlements

To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements as an alternative to toll hearings since the mid-1980s. In September 1988, the Board issued its first *Guidelines for Negotiated Settlements*. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements.

Most of the major Group 1 companies have successfully negotiated multi-year settlements with their shippers. Beginning in 1995, the Board approved a succession of multi-year settlements. These agreements generally included incentives to reduce costs and provisions to share savings between the pipeline company and its shippers. Several of these multi-year settlements have been renegotiated upon their expiry. For example, Enbridge Pipelines has negotiated three consecutive five-year settlements covering the period 1995 to 2009. Similarly, TPTM and TQM have had two successive five-year settlements and are in the process of renegotiating new ones. Refer to Figure 22 which shows, for each pipeline company, the years that were covered by negotiated settlements.

FIGURE 22

Negotiated Settlements Timeline



Notes:
1 - Foothills is regulated under an actual cost of service methodology
2 - RH-1-2000 Hearing for tolls from 1 December 1999 to 30 September 2000
3 - RH-1-2001 Hearing to consider contested settlement for 2001 and 2002 tolls
4 - RH-1-2002 Hearing for 2003 tolls
5 - RH-2-2004 Hearing for 2004 tolls
6 - In negotiations
7 - Westcoast and its shippers have negotiated a 2-year settlement
Alliance and M&NP were not in service during these years

Negotiated settlements have contributed to a significant reduction in the regulatory burden for all parties with less time spent participating in hearings and a corresponding reduction in costs associated with the hearing process. This may be somewhat offset by the increased time spent by pipeline companies and their shippers in task force meetings. Parties note that the greater use of task forces and settlements has increased the collaboration between pipeline companies and shippers and resulted in a better alignment of interests.

Some settlements have included various innovative performance mechanisms such as incentives for cost control and performance improvement standards. Examples of the latter include the service standards in Westcoast's 1997–2001 settlement and the service and reliability metrics in Enbridge's 2005–2009 incentive agreement.

Negotiated settlements have also increased the length of period for which tolls are set. Rather than annual toll proceedings, a number of agreements have terms of five years or longer, which provides greater predictability and stability.

2.3 Shipper Satisfaction

2.3.1 *NEB Pipeline Services Survey*

The Board conducted its second Pipeline Services Survey in early 2006 to obtain direct feedback from the shippers on the level of service provided by major NEB-regulated pipeline companies. The Board also uses this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

This year, the Board used a web-based survey tool to send the survey directly to shippers via e-mail. Shippers were sent one survey for each pipeline the shipper utilized during the past year. Each survey asked the shippers to provide their company's corporate views on the services provided by the pipeline being surveyed and on the services provided by the Board. The overall response rate of 33.5 percent was a significant improvement over last year's rate of 23 percent.

After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each pipeline company and its shippers with detailed company-specific results. These results include the pipeline company's average rating, distribution of responses for each question as well as the verbatim comments received from shippers, excluding the names of the respondents.

The Board follows up on the survey results, including feedback on the Board, by meeting with pipeline companies and shippers.

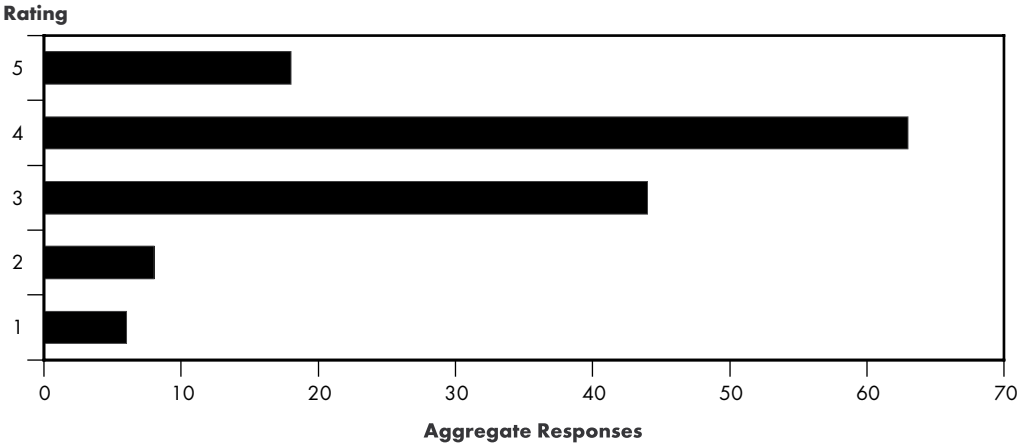
Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/SurveyResults.

Pipeline Services

Figure 23 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). While the average score of 3.57 was lower than the score of 3.78 in last year's survey, shippers still appear reasonably satisfied with the services provided.

FIGURE 23

Overall Quality of Service



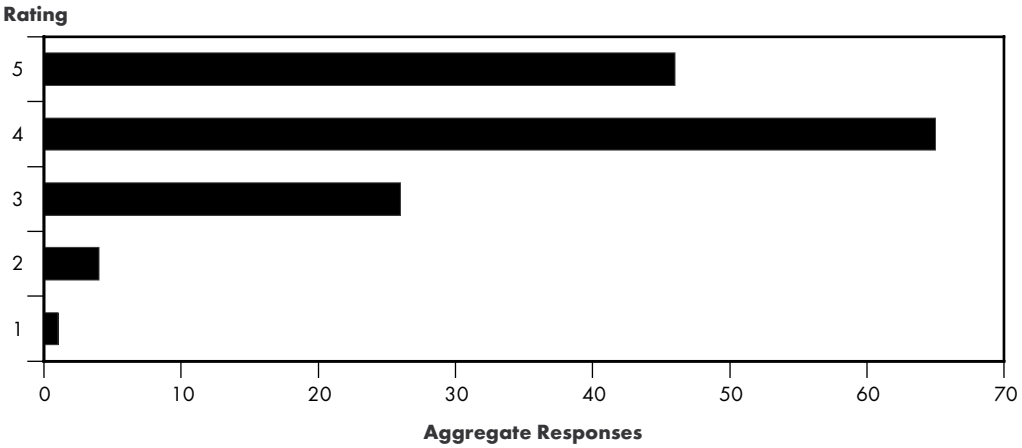
The three areas where the pipeline companies rated the highest were the same areas as in last year's survey, as demonstrated by the scores on the following questions:

1. How satisfied are you with the physical reliability of the pipeline company's operations?
2. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?
3. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the company?

The high level of satisfaction with the physical reliability of pipeline operations indicates that energy products are reliably being delivered to markets (see Figure 24).

FIGURE 24

Physical Reliability of Operations



The three areas where shippers believe that pipeline companies could improve the most are very similar to the areas in last year's survey. The questions where the pipeline companies rated lower were:

1. How satisfied are you that this pipeline company's tolls are competitive?
2. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?
3. How satisfied are you with the collaborative process (negotiations or task force meetings) utilized by this pipeline company?

Performance of the Board

The survey also indicated that approximately two-thirds of shippers are either satisfied or very satisfied with the Board's performance in creating an appropriate regulatory framework and with the Board's processes to resolve disputes. While this was a slight improvement over the previous year's survey, shippers did identify areas where the Board could improve its processes and performance.

2.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a complaint to the NEB. It can then be dealt with through appropriate dispute resolution (ADR), through a formal complaint process or the parties may continue to negotiate towards resolution. There were two shipper complaints this past year requiring a formal process before the Board:

Abitibi Consolidated Company (Abitibi) and Boise White Paper, L.L.C. (Boise)

Centra Transmission Holdings Inc., a Group 2 company, applied to the Board to increase its tolls. Subsequently two shippers, Abitibi and Boise wrote to the Board requesting additional time to examine Centra's application. The Board subsequently initiated a written process to deal with the matter. The Board approved Centra's application for increased tolls, subject to certain amendments. Additional information can be found in the Board's Reasons for Decision RHW-3-2005.

Petro-Canada Oil and Gas (PCOG)

PCOG applied to the Board requesting the issuance of an order requiring Westcoast to grant the permanent firm service relocation of PCOG's Transportation North Long Haul firm service without the requirement to extend its existing service agreement by two years. On 4 May 2006, the Board issued its decision on PCOG's application. The Board found that the practice of requiring a term extension does not constitute unjust discrimination and that permanent relocation may be considered a service. The Board was also of the view that not enough information concerning the appropriate level of consideration was included in the submissions. The Board directed Westcoast to bring the matter of permanent firm service relocation and the appropriate level of consideration back to the Board after discussion with the Tolls and Tariff Task Force. Further, the Board advised that PCOG's term extension, if any, will reflect the final Board decision in this matter. Additional information can be found in the Board's file, 4775-W005-1-17.

2.3.3 Service Enhancements

Pipeline companies modify their services on an ongoing basis as circumstances change or innovative ideas are brought forward. Normally, the pipeline or its shippers bring these proposed service enhancements to their tolls task force for discussion and review prior to submission to the Board and ultimate adoption. This past year, for example, Westcoast applied to the Board to introduce firm service enhancements of term differentiated rates and authorized over run service in Zones 3 and 4 and cross corridor crediting in Zone 3. The Board approved Westcoast's application. More information can be found in the Board's Reasons for Decision RHW-1-2005.

If the task force is unable to resolve the issue, a party may bring the issue directly to the Board. This past year, one such enhancement was brought to the Board and subsequently approved.

Coral Energy Canada Inc. (Coral)

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its Mainline. The Board approved Coral's application and directed TransCanada to modify its Mainline Transportation Tariff to reflect this decision. Additional information can be found in the Board's Reasons for Decision RHW-2-2005.

2.3.4 Summary of Shipper Satisfaction

This past year, it was found that shippers are reasonably satisfied with the services provided by the pipeline companies and the Board's performance in creating an appropriate regulatory framework and the Board's processes to resolve disputes. For both the pipeline companies and the Board, shippers identified areas for improvement in service. Areas of improvement for the pipeline companies are outlined in the previous section. Shippers also noted that the Board could improve its processes through which tolls and tariffs are determined by streamlining those processes and actively engaging stakeholders so that it better understands

the market context in which it makes decisions. The Board is taking this feedback into consideration. For example, in its Strategic Plan for 2006 – 2009 the Board identified the objective for its regulatory processes to be efficient, seamless and responsive to all stakeholders.

2.4 Pipeline Financial Integrity and Ability to Attract Capital

In order for a hydrocarbon transportation system to be efficient, pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions. This enables them to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors used to assess these areas.

2.4.1 Financial Ratios

Financial statement information can be used to create financial ratios that are used for assessing a company's performance and financial integrity. Evaluating a financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. These ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Some reported financial information may pertain to a parent company, which may include non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some of the ratios used to assess the financial risk and operating profitability of certain NEB-regulated pipeline companies. The final section outlines and discusses some NEB-approved financial ratios.

Financial Risk

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk attributed to the nature of a particular business activity and, for pipelines, typically includes supply, market, regulatory, competitive and operating risks. Financial risk increases as the proportion of debt increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of financial risk gives some indication of its financial viability.

Ratios used to evaluate a company's level of financial risk include interest coverage, fixed-charges coverage, and cash flow-to-total debt and equivalents.

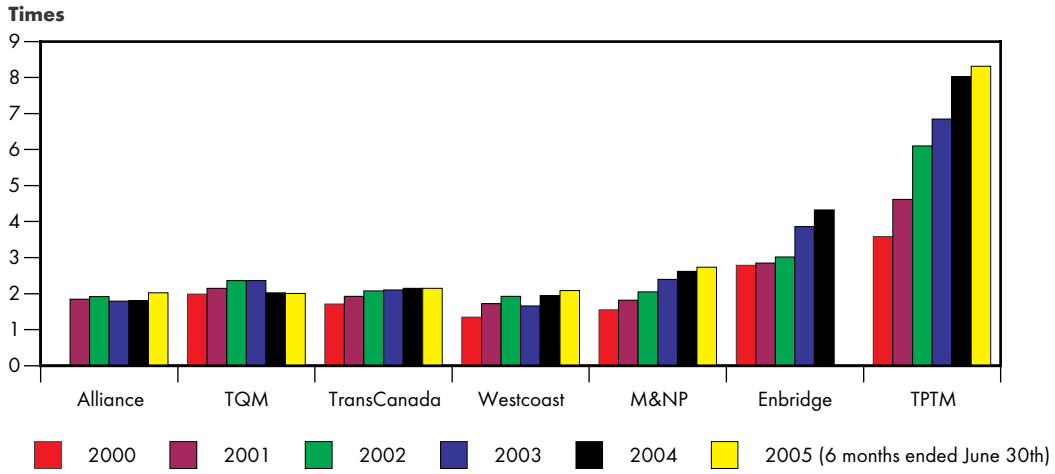
Interest and Fixed-Charges Coverage Ratios

An interest coverage ratio assesses a company's ability to make interest payments and repay its debt obligations. It is defined as Earnings Before Interest and Taxes (EBIT) divided by interest charges. A fixed-charges coverage ratio also assesses the ability to make interest payments and repay debt obligation; however, it also takes into consideration other types of fixed payments a company is obligated to make. It is defined as EBIT less other fixed-charges divided by interest and other fixed-charges. Higher ratios indicate an increased likelihood that the company will be able to meet its obligations and may indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 25. The average fixed-charges coverage

FIGURE 25

Fixed-Charges Coverage Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge in 2005.

ratio for these companies for the six months ending June 2005 is 3.22 times. TPTM's fixed-charges coverage ratio is higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carries less debt and, therefore, has lower fixed payments.

From 2000 to 30 June 2005, the fixed-charges coverage ratio for these pipeline companies increased on average by 49 percent[7]. This growth was primarily driven by M&NP, Enbridge and TPTM. No company saw its fixed-charges coverage ratio decline from its 2000 level. The consistent increases in fixed-charges coverage ratios is one metric signaling a decrease in these pipeline companies' financial risk, when considered as a group.

Cash Flow-to-Total Debt and Equivalents Ratio

The cash flow-to-total debt and equivalents ratio is another way of assessing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate that it has greater borrowing capacity.

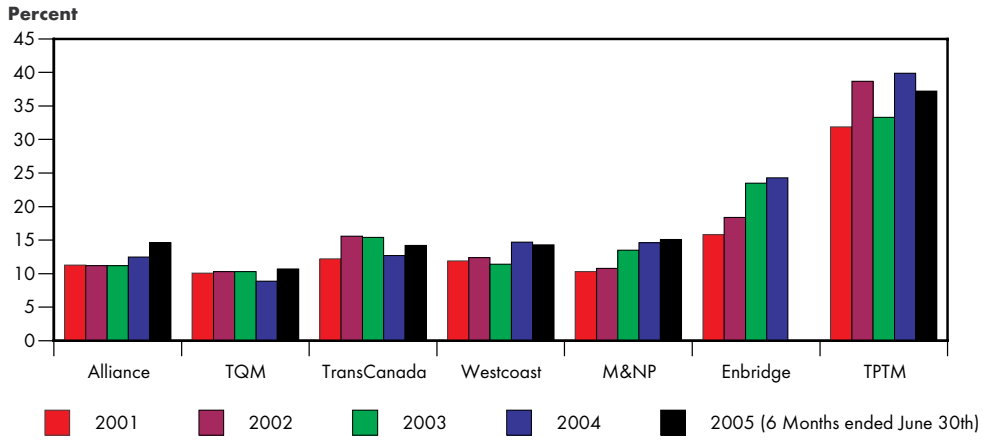
The cash flow-to-total debt and equivalents ratios for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 26. The average cash flow-to-total debt and equivalents ratio for these companies was 17.68 percent for the 6 months ending June 2005. TPTM's cash flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by 20 percent from 2000 to 2005. The increase has been steady without any noteworthy periods of deterioration. Similar to the fixed-charges coverage ratio, the consistent increase in cash flow-to-total debt and equivalents ratios is another metric which signals that, on average, these pipeline companies' financial risk has been decreasing.

[7] Historically, Enbridge's fixed-charges and cash flow-to-debt and equivalents ratios were much higher than the average of the other pipeline companies in Figures 20 and 21. Since these ratios were not provided for Enbridge in 2005, the pipeline company average for 2005 and the percentage increase since 2000 and 2001 respectively, may be biased downward.

FIGURE 26

Cash Flow-to-Total Debt and Equivalents Ratios



Source: DBRS

N.B. There was no cash flow-to-total debt and equivalents ratio reported for Enbridge in 2005.

Operating Profitability

Return on Common Equity

ROE is commonly used to assess the operating profitability of a company. ROE is defined as net income divided by common equity. For NEB-regulated pipeline companies, this is the return on the equity portion of the rate base that is approved by the Board. A higher ROE is typically preferred by both bondholders and, even more so, by equity investors.

Table 4 shows the achieved ROE for several NEB-regulated pipeline companies from 2000 to 2005 along with the NEB-approved ROE in accordance with the RH-2-94 Formula[8] (RH-2-94 Formula ROE). Alliance, Enbridge, M&NP and TPTM are not subject to the RH-2-94 Formula ROE as they have all negotiated an ROE with their shippers[9]. As per their respective negotiated settlements, Enbridge and TPTM are not required to submit their achieved ROE to the NEB. Therefore, neither of these pipeline companies are included in Table 4. Westcoast's Field Services Division is also not subject to the ROE formula as it is under light-handed regulation[10]. Its tolls for gathering and processing services are negotiated individually with shippers.

From 2000 to 2005, most pipeline companies subject to the RH-2-94 Formula ROE have consistently had ROEs in the mid-to-high nine percent range (except for Westcoast Transmission which has achieved higher ROEs). The RH-2-94 Formula ROE for 2006 is 8.88 percent.

NEB-Approved Ratios

When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a ROE and deems a common equity ratio for the regulated entity. Therefore, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

8 Formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

9 These pipelines settlements are subsequently approved by the Board.

10 Light-handed regulation is essentially regulation on a complaint basis with rules. Additional information can be found in RHW-1-98.

TABLE 4

Achieved ROEs and the RH-2-94 Formula ROE (Percent)

	2000	2001	2002	2003	2004	2005
Alliance	11.21	11.25	11.25	11.25	–	–
Foothills	9.90	9.61	9.53	9.79	9.56	9.46
M&NP	13.80	14.20	12.95	12.31	13.75	14.31
TQM	9.96	10.21	9.80	10.21	9.84	9.92
TransCanada	9.99	9.72	9.95	10.18	9.83	9.66
B.C. System	9.90	6.86	9.53	8.21	8.51	9.46
Westcoast Field Services	–	13.62	14.87	6.76	11.63	12.48
Westcoast Transmission	12.68	15.84	13.44	12.93	10.28	10.82
NEB RH-2-94 Formula	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**

Source: NEB Surveillance and Annual Reports; dash indicates not available

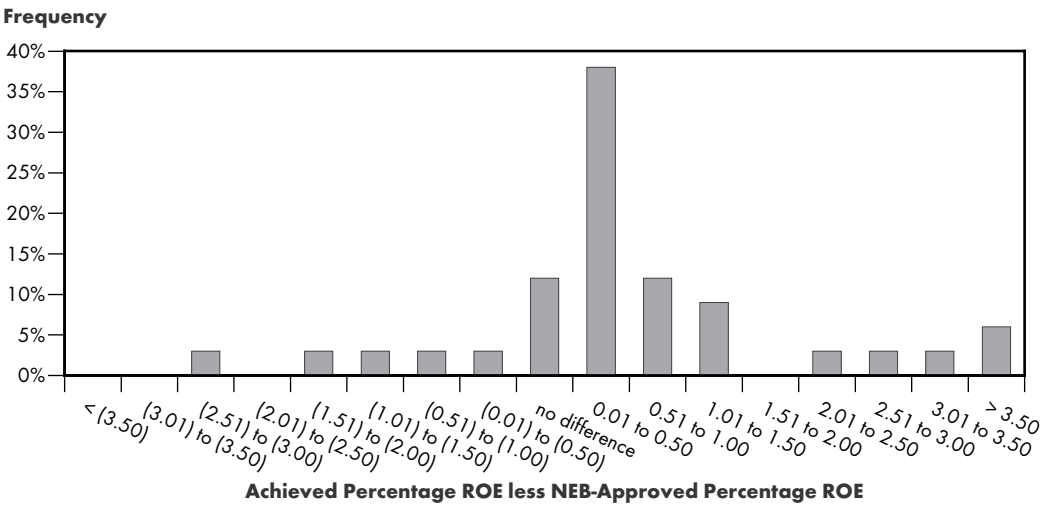
NEB-Approved Return on Common Equity

NEB-approved ROEs have great influence over the ROEs that are actually achieved. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentive and profit sharing mechanisms and cost reductions over the year.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for TransCanada, B.C. System, TQM, Westcoast Transmission system, and M&NP[11]. Enbridge and TPTM are not required to submit their achieved ROEs to the Board as per their negotiated settlements. Westcoast Field Services is not included as it is subject to light-handed regulation. Foothills and Alliance are not included in Figure 27 as neither is able to over- or under-perform on ROE in accordance with their respective cost-of-service methodologies.

FIGURE 27

Achieved and NEB-Approved ROE for the Years 1999 to 2005



11 TransCanada, B.C. System, TQM and Westcoast Transmission system have NEB-approved ROEs subject to the RH-2-94 Formula ROE, whereas M&NP has a NEB-approved ROE of 13 percent.

From 1999 to 2005, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 85 percent of the time. This stability and predictability of their operating profitability is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet and outperform approved levels through cost reductions, incentive and profit sharing mechanisms.

NEB-Approved Deemed Common Equity Ratios

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations. The Board approves a deemed common equity ratio[12] for most of the Group 1 pipeline companies that it regulates.

TABLE 5

Deemed Common Equity Ratios (Percent)

	2000	2006
Alliance	30	30
Foothills	30	36
M&NP	25	25
TQM	30	30*
TransCanada	30	36
B.C. System	30	36
Westcoast Transmission	30	31*

* TQM and Westcoast Transmission's 2006 deemed common equity ratios are interim.

Table 5 shows the deemed common equity ratio for some NEB Group 1 pipeline companies. TransCanada, Westcoast Transmission, B.C. System and Foothills have had their deemed common equity ratios increased between 2000 and 2006. These increases are credit positive and lower the financial risk of the pipeline companies.

2.4.2 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies: DBRS, Standard & Poor's (S&P), and Moody's Canada Inc. (Moody's). A comparison of the rating scales for DBRS, S&P and Moody's can be found in Appendix 1. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, using these ratings as an accurate measure of the creditworthiness of a NEB-regulated pipeline owned by a company with both regulated and non-regulated operations, such as TransCanada and Enbridge, must be interpreted with some care. In addition, credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies.

Dominion Bond Rating Service

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While key considerations will vary from industry to industry, some of the common factors considered for most ratings are: core profitability, asset quality, strategy and management strength, and financial and business risk.

The following factors are also important considerations in deriving the credit ratings for pipelines and electric and gas utilities: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. DBRS credit ratings for several NEB-regulated pipeline companies are shown in Table 6. As indicated, these ratings have remained stable from 2000 to the present, varying from BBB (high) to A (high).

[12] A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

Standard & Poor's

A credit rating from S&P reflects its current opinion of a company's overall capacity to pay its financial obligations. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent. S&P's opinion may also apply to specific financial obligations.

In S&P's rating methodology, a company rated "A" has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated "BBB" has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to weaken the company's capacity to meet its financial commitments.

S&P credit ratings for several NEB-regulated pipeline companies are shown in Table 7. This table indicates that these ratings have been relatively stable from 2000 to the present, ranging from BBB (stable) to A (negative).

Both DBRS and S&P have, at various times, expressed an opinion that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Notwithstanding these comments, the ratings assigned by both of these agencies for the NEB-regulated companies are all investment grade.

Moody's

Moody's credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic questions:

1. What is the risk to the debt holder of not receiving timely payment of principal and interest on this specific debt security?
2. How does the level of risk compare with that of all other debt securities?

Like S&P, Moody's credit rating is its current opinion of a company's overall capacity to pay its financial obligations and focuses its ratings on the overall creditworthiness of a consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future. This determination is built on an analysis of the strengths and weaknesses of the individual issuer compared with those of its peers worldwide. Moody's also takes into consideration factors external to the issuer, including industry or nation-wide trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of company management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several NEB-regulated pipeline companies are provided in Table 8. All of Moody's ratings place these pipelines in the investment grade category, ranging from "medium grade" to "upper-medium grade".

TABLE 6

DBRS Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
Alliance	BBB(high)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
M&NP	A	A	A	A	A	A	A
TQM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
TransCanada	A	A	A	A	A	A	A
Westcoast[1]	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
Enbridge	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)
Express[2]	NR	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
TPTM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	discontinued /debt repaid
TNPI	NR	NR	NR	NR	NR	A(low)	A(low)

Notes: (1) Unsecured debentures; (2) Senior secured

NR Not reported

TABLE 7

S&P Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
TQM	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable
TransCanada	A-/Stable	A-/Stable	A-/Watch Negative	A-/Watch Negative	A-/Watch Negative	A-/Negative	A-/Negative
Westcoast	A-/Negative	A-/Stable	A/Negative	BBB/Stable	BBB/Positive	BBB/Watch Negative	BBB/Stable
Enbridge	A-/Stable	A-/Negative	A-/Negative	A-/Stable	A-/Stable	A-/Stable	A-/Stable
TPTM	BBB+/Stable	BBB+/Stable	BBB+/Watch Negative	BBB/Stable	BBB/Stable	BBB+/Stable	discontinued / debt repaid

TABLE 8

Moody's Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
Alliance[1]	Baa1	A3	A3	A3	A3	A3	A3
M&NP[2]	A1	A1	A1	A1	A1	A2	A2
TransCanada[1]	A2	A2	A2	A2	A2	A2	A2
Enbridge	NR	NR	NR	NR	NR	NR	NR
Express[2]	A3	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1

Notes: (1) Senior unsecured; (2) Senior secured

2.4.3 Comments by Investment Community

As noted previously, pipeline companies must be able to access capital markets to maintain and, potentially, expand their systems as the needs of the transportation market change. Board staff met with credit rating analysts, equity analysts (sell-side analysts), and suppliers of capital such as insurance and pension funds (buy-side analysts) to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets, as well as their views on transportation markets and the current regulatory environment in Canada. This section reflects the views expressed in those meetings.

All parties expressed the view that there was no problem accessing debt markets at this time. In fact, utilities frequently enter the market to refinance their debt and, given the current liquidity in the markets, they have been able to do so at favourable spreads relative to government bonds.

Several analysts noted that Canadian regulation, including the ROE formula approach, provides transparency, predictability and stability, which are seen as highly beneficial. However, a number of analysts felt that the ROE generated by the NEB ROE formula and the formulas of other Canadian regulators were "a little too low" and not supportive of dividend growth or credit metrics. Although most analysts felt that utilities have good access to equity markets, the current level of ROEs was seen by some as impeding this access. As there has been, in most cases, adequate pipeline capacity from the WCSB in recent years, the ability of pipeline companies to access equity markets has not been significantly tested.

Many equity analysts publish their assessments of various companies for investors. Most of the analysts currently rate major NEB-regulated pipeline companies in the "Hold" or "Buy" categories. A number of equity analysts commented that where they have "Buy" ratings on Canadian utility stocks, they tend to reflect the prospects of the companies' non-regulated businesses. A number of analysts also noted that companies have reduced costs and taken other steps to support corporate profit and dividend growth for several years, and they questioned how long this can continue.

It was noted that pipeline stocks are part of the interest-sensitive segment of the equity market and as such, low interest rates have been positive for valuations and the price-to-earnings ratio. The price-to-earnings ratios of Canadian utilities have been higher than their U.S. and European counterparts. The reasons given for this difference included greater growth opportunities in Canada given oil sands, northern gas, power infrastructure development, a more stable regulatory environment, as well as strong foreign interest in Canadian stocks in general.

2.4.4 Summary of Pipeline Financial Integrity and Ability to Attract Capital

The financial information and observations by the investment community are summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2000.
- Deemed common equity ratios have increased since 2000.
- Achieved ROEs have, in most cases, been greater than or equal to their NEB-approved levels between 1999 and 2005.
- Achieved ROEs have been stable and predictable.
- Credit ratings continue to be strong.
- The investment community is of the view that NEB-regulated companies should have no problems accessing the capital markets at this time.

These observations signal that, currently, NEB-regulated pipelines have adequate financial integrity to attract capital on reasonable terms and conditions.

2.5 Proposed Pipelines

Many proposals to expand pipeline capacity or build new pipeline systems have been announced, applied for or recently approved. These include gas pipelines to growing markets in Canada and the U.S. and pipelines to ship western Canadian crude oil to the West Coast for delivery to Washington State and offshore markets, the U.S. Midwest and southern PADD II and the U.S. Gulf Coast (PADD III). More specifically, these project proposals include:

- new pipelines connecting northern gas supplies to existing gas infrastructure;
- natural gas expansions in the east to facilitate market development in eastern Canada and the U.S. Northeast; and
- pipeline laterals connecting existing infrastructure to proposed LNG receiving terminals in Nova Scotia and New Brunswick; and
- oil pipeline expansions and new pipeline proposals to facilitate the expected growth in the next decade in oil sands production.

Natural Gas

In the coming decade, demand for natural gas in North America is expected to exceed the growth in North American domestic supplies. In Canada, there are two sectors of growth that bear noting: oil sands projects in Alberta and electricity generation in Ontario.

The Canadian oil sands projects are a large and growing market for natural gas. Today, these projects consume about 0.7 Bcf/d. Natural gas is used to generate power, generate steam for in situ oil production and upgrade bitumen into synthetic blends. Gas demand for oil sands is expected to more than double to perhaps 2 Bcf/d over the next decade depending on the number of oil sands projects that proceed and the technology used.

In addition, Ontario's policy to remove 7 500 MW of coal-fired electrical generation by 2009 may require significant supplies of natural gas for power generation While refurbishment of existing nuclear generation and the addition of renewable power sources may meet part of the requirement, it is possible that new electrical generation will primarily be fired by natural gas.

Table 9 summarizes currently announced Canadian natural gas pipelines and expansion proposals.

TABLE 9

Announced Canadian Natural Gas Pipelines and Expansions

Pipeline	Location	Capacity Increase (Bcf/d)	Proponents' Estimated Completion Date	Market to be Served
TransCanada PipeLines Limited – 2006 Eastern Mainline Expansion	Ontario, Québec	.310[13]	Late 2006	Central Canada, Northeastern U.S.
TransCanada PipeLines Limited– 2007 Eastern Mainline Expansion	Ontario, Québec	.377[14]	2007	Central Canada, Northeastern U.S.
Mackenzie Gas Pipeline	Mackenzie Delta, Northwest Territories to Alberta	1.2	2011	North America
Maritimes & Northeast Pipeline – Brunswick Pipeline	New Brunswick	0.75	2008	Atlantic Canada, Northeastern U.S.
Maritimes & Northeast Pipeline – Bear Head Pipeline	Nova Scotia	.813	N/A	Atlantic Canada, Northeastern U.S.

N/A Not Available

13 TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Iroquois delivery point.

14 TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Les Cèdres (148 MMcf/d), Philipsburg Extension to Philipsburg (12 MMcf/d) and Kirkwall/Niagara Line to Chippawa (217 MMcf/d).

Liquefied Natural Gas

A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Furthermore, advances in liquefaction and transportation technologies have lowered the unit cost of LNG by 30 percent over the past decade, enabling the use of LNG as a cost competitive source of gas supply in North America. In anticipation of growing natural gas requirements, expansions of some existing U.S. terminals and numerous new receiving facilities have been proposed, including sites in Canada as shown in Table 10.

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. As discussed above, pipeline laterals will be required to connect LNG receiving terminals to existing natural gas pipeline infrastructure in order to deliver the gas to market.

TABLE 10

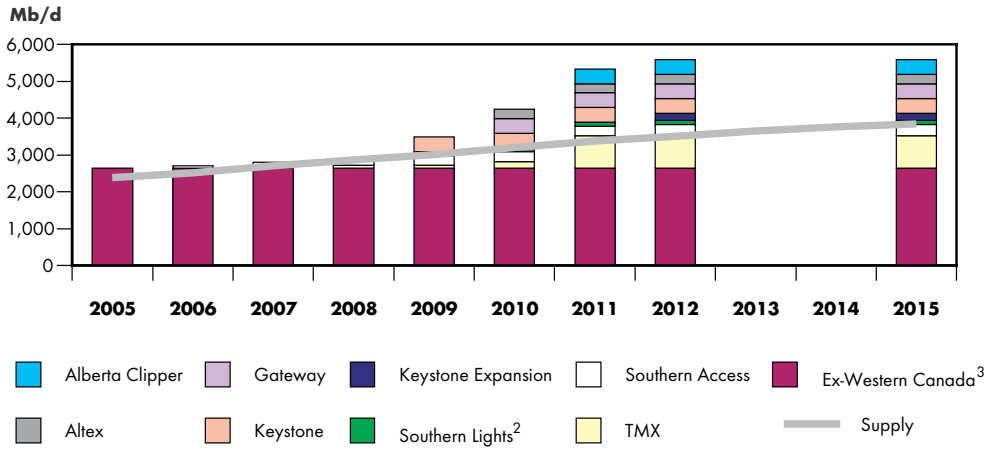
Proposed Canadian LNG Terminals

Terminal	Company	Location	Capacity (Bcf/d)	Proponents' Estimated Completion Date	Market to be Served
1 Bear Head	Anadarko Petroleum Company	Point Tupper, Nova Scotia	0.750 to 1.00	N/A	Atlantic Canada, Northeast U.S.
2 Keltic Goldboro	Keltic Petrochemicals Inc.	Goldboro, Nova Scotia	1.00	Late 2009	Atlantic Canada, Northeast U.S.
3 Cacouna Energy	TransCanada PipeLines Limited and Petro-Canada	Gros Cacouna, Québec	0.50	2010	Québec, Ontario, Northeast U.S.
4 Rabaska	Gaz Metro Limited Partnership, Gaz de France and Enbridge Inc.	Beaumont, Québec	0.50	2010	Québec, Ontario
5 Canaport	Irving Oil Limited and Repsol YPF	Saint John, New Brunswick	1.0	Late 2008	Atlantic Canada, Northeast U.S.
6 WestPac Prince Rupert	WestPac Terminals Inc.	Ridley Island, British Columbia	0.15 to 0.50	2009	Westcoast North America
7 Kitimat	Galveston Energy	Port of Kitimat, British Columbia	0.61	2009	Westcoast North America
8 Statia	Statia Terminals Canada Partnership	Canso Strait, Nova Scotia	0.50	N/A	Atlantic Canada, Northeast U.S.

N/A Not Available

FIGURE 28

NEB Supply Forecast and Proposed Pipeline Projects and Timing



1 The pipeline projects are listed alphabetically. In-service dates are proposed by the project sponsors

2 Edmonton to Cromer

3 Total pipeline capacity out of the WCSB

TABLE 11

Announced and Proposed Canadian Oil Pipelines and Expansions

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TPTM)		**75**		PADD V
Phase One TMX1	Filed July 2005	35	April 2007	Offshore/Far East
Phase Two TMX1	Filed February 2006	40	Nov. 2008	
Southern Option		**700**[1]		PADD V
TMPL TMX2	01Q2007	100	Jan. 2010	Offshore/Far East
TMPL TMX3	N/A	300	Jan. 2011	
Northern Option (TMX)	N/A	**450**	2011	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	Fall 2006	**400/150**	Mid-2010	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights	N/A			
Southern Lights (diluent)		**180**		
Line 2 Expansion (oil)		**169**	2009	Alberta
Edmonton to Cromer		103		PADD II
Cromer to Clearbrook		33		PADD II
Clearbrook to Superior		33		PADD II
TCPL Keystone	June 2006	435	2009	Southern PADD II/ PADD III
Alberta Clipper	N/A	**400**	2010/11	Southern PADD II
Altex Energy	N/A	250	4Q2010	PADD III
Enbridge (Southern Access)		**315**		Midwest/Southern
Phase I	May 2006	120	Oct. 2006 and Feb. 2007	PADD II
Phase II	N/A	148	2008/09	
Phase III	N/A	47	N/A	

N/A Not Available

1 The 700 mb/d includes the existing capacity of 300 mb/d and the capacity additions from TMX2 and TMX3.

Oil

High crude oil prices and strong global demand are key drivers in the expansion of the oil sands. In this regard, many proposals to expand existing pipelines or build new facilities have been announced. Figure 28 shows that pipeline capacity out of western Canada could be tight in 2008.

Table 11 illustrates announced and potential expansions by Canadian pipelines. Additional details about these proposals are found in the EMA entitled *Canada's Oil Sands Opportunities and Challenges to 2015: An Update*, released in June 2006.

The proposals for pipeline expansion and construction of new pipelines indicate that the market is responding to increases in supply and demand.

2.6 Emerging Issues

While the transportation system is currently working well, there are a number of challenges facing the industry.

The demand for natural gas in North America is expected to increase by about two percent per year over the next decade. Conventional sources of supply for natural gas in North America are not likely to meet the increased demand. LNG is the fastest growing fuel source worldwide, and LNG's market share in North America is estimated to grow to about 15 percent within the decade. Although there is uncertainty around the number of LNG terminals that will be built in North America and the potential effects that imported LNG will have on the supply, demand and pattern of natural gas flow, LNG could become an important component of gas supply in Canada.

The construction of LNG terminals could have implications for existing pipeline transportation systems. For some pipelines, such as the TransCanada Mainline, this could result in volumes from the WCSB being displaced. For others, such as PNGTS and M&NP on the east coast, there is the possibility of higher capacity utilization on their systems. Direction of flow and toll design may also be affected. The PNGTS pipeline system has the potential for backhauls or reversal to import gas into Canada. There are also possibilities for expansion, reversals or backhauls in Quebec on TQM. Northern gas projects such as the Mackenzie Valley Pipeline or a pipeline from Alaska, if approved, and constructed, would also affect flows on existing systems.

If the expected increase in natural gas demand for power generation in Ontario materializes, it will impact the balance of supply and demand and consequent gas flows. The impact of this power generation on pipeline infrastructure will depend on the total amount of generation built and its location. New pipeline services may also be required to satisfy the needs of the power generation customers.

The expected growth in oil sands production is forcing industry to address questions such as which incremental markets to serve and how to expand the pipeline system to access them efficiently. Options include expanding existing systems and constructing new systems to access new markets in the U.S. and/or Asia. Given the large capital outlay and the relative irreversibility of the investment, market participants want to ensure that the optimal decisions are made.

There is concern in industry and in the financial community about the potential for insufficient pipeline capacity, particularly oil capacity, and conversely, the potential for excess capacity if too many projects go ahead. Other issues include the financial implications of increasing levels of competition among oil pipelines and the manner in which the regulatory process would unfold if numerous competing applications come before the NEB.

The challenge for the pipeline transportation industry is to have appropriate pipeline capacity in service to correspond to increases in production and growing market needs. For this to happen, there must be recognition of adequate lead times to achieve sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct. A key component is that the regulatory process continues to be fair and effective with clear timelines and clear requirements.

Some of the above-noted issues will be settled among market participants; others may be examined in formal proceedings before the Board. The Board will continue to consult with stakeholders and seek input if and when any regulatory initiatives are pursued.

Filed: 2008-04-08
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Attachment 12

CONCLUSIONS

In the Introduction to this report, the Board identified its assessment criteria. Based on these criteria the Board continues to believe that, at the present time, the Canadian hydrocarbon transportation system is working effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The basis differentials and capacity utilization charts show that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. Some excess capacity out of the WCSB and the unprecedented high prices for energy has provided producers with the flexibility to access markets of their choice at most times. However, there are constraints at the market end of some pipelines as indicted by expansions currently underway.

   Capacity is tight on oil pipeline transportation systems. While the capacity utilization charts show that there is spare capacity on some of the pipelines, additional capacity is required to meet the growing demand, provide flexibility and enhance market penetration. The need for additional capacity is best shown by the number of announced and proposed pipelines and expansions.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipeline companies.** The results of the NEB Pipeline Services Survey again rate the physical reliability of pipeline operations very highly, while satisfaction with toll competitiveness was again identified as the area where shippers most had concerns.

3. **NEB-regulated pipeline companies are financially sound** and able to attract capital on reasonable terms and conditions. While it is recognized that some of the data and indicators reviewed is for the consolidated operations of pipeline companies, discussion with the investment community indicated that, at this time, NEB-regulated pipeline companies should have no difficulty raising capital. Extensive investment will be required in the future to provide needed infrastructure and the financing for those facilities will depend upon the characteristics of the projects and the financial markets at that time.

As identified in Section 2.5 there are a significant number of proposals to build or expand Canadian pipelines to deliver additional volumes of oil and natural gas to growing markets. Some of these proposals may be competing for the same sources of supply and perhaps the same markets.

The challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve coordinating with other jurisdictions. Investors desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained.

The Board recognizes that this report is only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

Debt Rating Comparison Chart

This chart provides a comparison of the rating scales used by DBRS, S&P and Moody's when rating long-term debt.

Credit Quality	DBRS	S&P	Moody's
Investment Grade			
Superior/High grade	AAA	AAA	Aaa
	AA (high)	AA+	Aa1
	AA	AA	Aa2
	AA (low)	AA-	Aa3
Good/Upper Medium	A (high)	A+	A1
	A	A	A2
	A (low)	A-	A3
Adequate/Medium	BBB (high)	BBB+	Baa1
	BBB	BBB	Baa2
	BBB (low)	BBB-	Baa3
Non-Investment Grade			
Speculative	BB (high)	BB+	Ba1
	BB	BB	Ba2
	BB (low)	BB-	Ba3
Highly speculative	B (high)	B+	B1
	B	B	B2
	B (low)	B-	B3
Very highly speculative	CCC	CCC	Caa1
	CC	CC	Caa2
	C	C	Caa3
	D	D	Ca
			C

Note: DBRS and S&P ratings in the CCC category and lower also have subcategories "high/+" and "low/-," and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category.

S&P's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A "Positive" outlook means that a rating may be raised; a "Negative" outlook means that a rating may be lowered and a "Stable" outlook means that a rating is not likely to change.

Pipeline Services Survey Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates "Very dissatisfied" and 5 indicates "Very satisfied". See the Board's website for the complete details.

1. How satisfied are you with the physical reliability of the pipeline company's operations?

1	2	3	4	5	Average
1	4	26	65	46	4.06

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc.)?

1	2	3	4	5	Average
1	4	26	65	46	4.06

3. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

1	2	3	4	5	Average
9	10	24	60	36	3.75

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the pipeline company?

1	2	3	4	5	Average
4	12	37	73	16	3.60

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc.) provided by the pipeline company?

1	2	3	4	5	Average
6	7	43	69	17	3.59

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
8	29	62	31	10	3.04

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
14	19	39	49	17	3.26

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	19	47	49	11	3.30

9. How satisfied are you with the suite of services offered by the pipeline company?

1	2	3	4	5	Average
4	17	51	55	10	3.37

10. How satisfied are you that this pipeline company's transportation tolls are competitive?

1	2	3	4	5	Average
14	29	45	38	11	3.02

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
8	12	51	42	8	3.25

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
7	11	48	47	6	3.29

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
6	8	44	63	18	3.57

14. On an overall basis, has the pipeline company's quality of service in the last year:

Improved	19	13%
Remained the Same	110	78%
Decreased	13	9%
Total	**142**	**100%**

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
7	7	30	72	8	3.54

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
3	7	23	54	4	3.54

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

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Attachment 12

Stakeholder Consultation

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
CIBC World Markets
Cochin Pipe Lines Ltd.
CPP Investment Board
Credit Suisse First Boston
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
First Energy Capital
Foothills Pipe Lines Ltd.
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Canada Inc.
Ontario Teachers' Pension Plan
RBC Capital Markets
Standard & Poor's
Sun Life Financial
TD Newcrest
Terasen Pipelines Inc.
Trans Mountain Pipe Line
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

Group 1 and Group 2 Pipeline Companies Regulated by the NEB

As of 31 December 2005

Group 1 Gas Pipelines
Alliance Pipeline Ltd.
Foothills Pipe Lines Ltd.
Gazoduc Trans Québec & Maritimes Inc.
Maritimes & Northeast Pipeline Management Ltd.
TransCanada PipeLines Limited
TransCanada PipeLines Limited B.C. System
Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

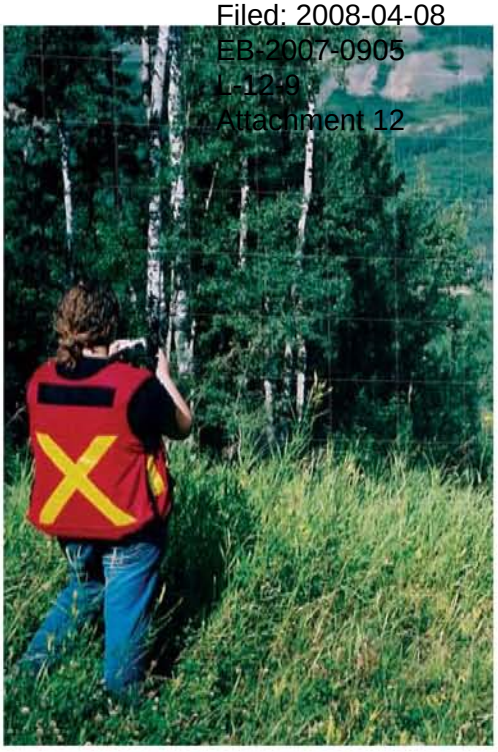
Group 1 Oil and Products Pipelines
Cochin Pipe Lines Ltd.
Enbridge Pipelines Inc.
Enbridge Pipelines (NW) Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipelines Inc.

Group 2 Natural Gas and Natural Gas Liquids Pipelines
AltaGas Pipeline Partnership
AltaGas Suffield Pipeline Inc.
AltaGas Transmission Ltd.
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Canadian Hunter Exploration Ltd.
Canadian Natural Resources Limited
Canadian-Montana Pipe Line Corporation
Centra Transmission Holdings Inc.
Champion Pipeline Corporation Limited
Chief Mountain Gas Co-op Ltd.
DEFS Canada L.P.
Devon Energy Canada Corporation
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
EnCana West Ltd.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.

Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Regent Resources Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Samson Canada, Ltd.
Shiha Energy Transmission Ltd.
Sierra Production Company
Suncor Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vector Pipeline Limited Partnership
County of Vermilion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

Group 2 Oil and Products Pipelines
Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited

ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd., as agent and general partner of the Pembina North Limited Partnership
PrimeWest Energy Inc.
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.



GOAL 3

Canadians benefit from efficient energy infrastructure and markets.

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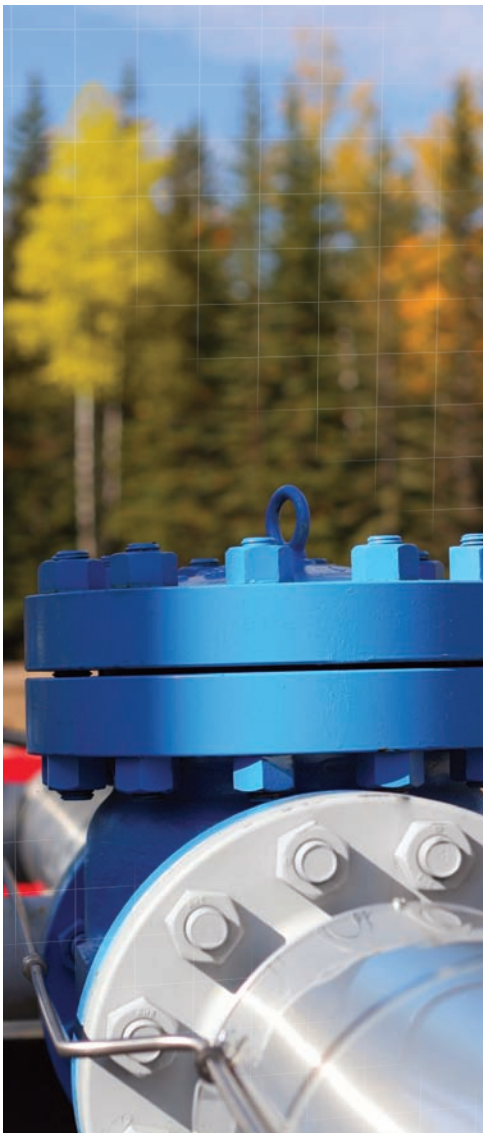
National Energy Board

Office national de l'énergie

CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT



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CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

JULY 2007

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ACRONYMS AND ABREVIATIONS

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
Altex	Altex Energy Ltd.
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
Cochin	Cochin Pipe Lines Ltd.
Coral	Coral Energy Canada Inc.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
Foothills	Foothills Pipe Lines Ltd.
FT	Firm Transportation
FT-RAM	Firm Transportation Risk Alleviation Mechanism
GDP	Gross Domestic Product
Gateway	Gateway Pipeline Inc.
IGUA	Industrial Gas Users Association
Irving/Repsol	Irving Oil Company Limited and Repsol YPF
Kinder Morgan	Kinder Morgan Canada Inc.
LNG	Liquefied Natural Gas
M&NP	Maritimes & Northeast Pipeline Management Ltd.

Mackenzie	Mackenzie Gas Project
Moody's	Moody's Canada Inc.
NEB or Board	National Energy Board
NGL	Natural Gas Liquid
OEB	Ontario Energy Board
PADD	Petroleum Administration for Defense Districts
Petro-Canada	Petro-Canada Oil and Gas
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Common Equity
S&P	Standard & Poor's
Terasen	Terasen Pipelines Inc.
T-South	Westcoast's Southern Mainline (Zone 4)
TNPI or Trans-Northern	Trans-Northern Pipeline Inc.
TPTM	Terasen Pipelines (Trans Mountain) Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
Union Gas	Union Gas Limited
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.

UNITS

b/d	Barrels per day
Mb/d	Thousand barrels per day
MMb/d	Million barrels per day
Bcf	Billion cubic feet
MMcf/d	Million cubic feet per day
GJ	Gigajoule
m^3/d	Cubic metres per day
$10^3m^3/d$	Thousand cubic metres per day

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines, as well as tolls and tariffs. Another key role is to regulate international and designated interprovincial power lines. The Board also regulates the imports of natural gas and the exports of natural gas, oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements. In its advisory function, the Board provides energy information and advice by analyzing information about Canadian energy markets obtained through regulatory processes and monitoring.

This report marks the third year that the Board has provided an assessment of the Canadian hydrocarbon transportation system. This report utilizes data from various publicly available sources which are collected and monitored by Board staff in addition to throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA), the Canadian Association of Petroleum Producers (CAPP), and the Canadian Gas Association (CGA) for comment. Other parties such as the Industrial Gas Users Association (IGUA) also expressed interest and provided comment on the issues and aspects of information in this report. A listing of all organizations that provided comment or information in the production of this report is shown in Appendix 1. Comments by all parties were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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Applications Business Unit
National Energy Board
Telephone: (403) 299-3690
Email: hmah@neb-one.gc.ca

If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: http://www.neb-one.gc.ca.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that changes as society's values and preferences evolve over time.

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INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver energy, in the form of natural gas, natural gas liquids (NGLs), crude oil, and petroleum products is critical to Canada's economic well-being. In 2006, approximately $110 billion worth of products was moved through Canadian pipelines to markets at home and in the U.S. The cost in 2006 of providing these transportation services is estimated to be around $4.7 billion, not including the fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates safely with minimal environmental impact.

Canadians depend on this infrastructure for a safe, reliable, and efficient energy supply. The 45 000 kilometres (km) of natural gas and oil pipelines regulated by the NEB are a crucial element in Canada's hydrocarbon transportation system (Figures 1 and 2). These include large-diameter, cross-country, high-pressure natural gas pipelines, low pressure crude oil and oil products pipelines, and small-diameter pipelines.

In line with its mandate to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest, the Board has identified five goals which articulate its purpose and core directives[2]:

1. NEB-regulated pipelines and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective support processes.

To determine whether the goals are being achieved, the Board has established various measures and a system of monitoring for each goal. Each year, the Board also issues various reports that discuss these different aspects of Canadian energy infrastructure and activities. This report focuses largely on aspects of Goal 3, and provides an update on the Board's assessment on how well the Canadian hydrocarbon transportation system is working. This report marks the third consecutive year for this assessment and utilizes the system of monitoring and measurements for the performance of the transportation system that was established in previous years. For the hydrocarbon transportation system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. The Board also reports annually on safety, integrity, and environmental performance of NEB-regulated pipelines in a companion report that was published in March 2007, which may be found at http://www.neb-one.gc.ca/safety/SafetyPerformanceIndicators/index_e.htm.

2 NEB Strategic Plan 2007-2010

FIGURE 1

Gas Pipelines Regulated by the NEB

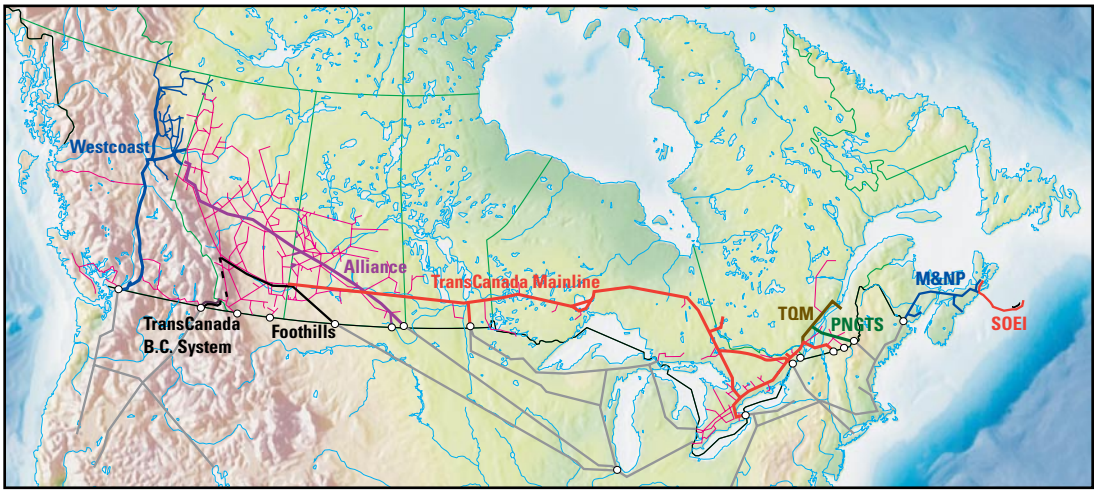
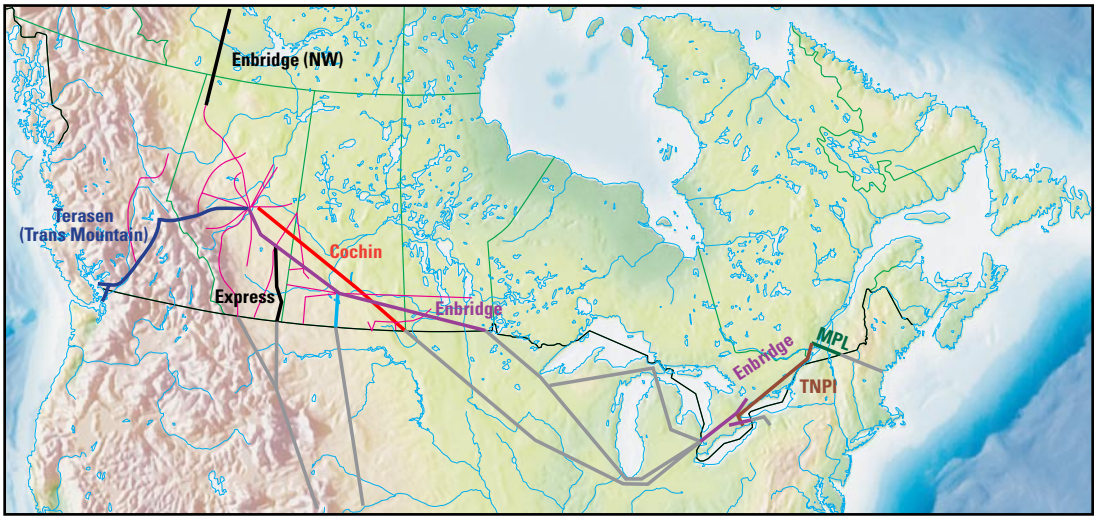


FIGURE 2

Oil Pipelines Regulated by the NEB



The Board believes that the following outcomes are important characteristics of a well functioning hydrocarbon transportation system:

- There is adequate pipeline capacity in place to move products to consumers who need them;
- Pipeline companies provide services that meet the needs of shippers at just and reasonable prices; and,
- Pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

In general, an efficient hydrocarbon transportation system will have an ability to respond on a timely basis to changing market conditions. This may entail adjustments to pipeline capacity or enhancement of pipeline services.

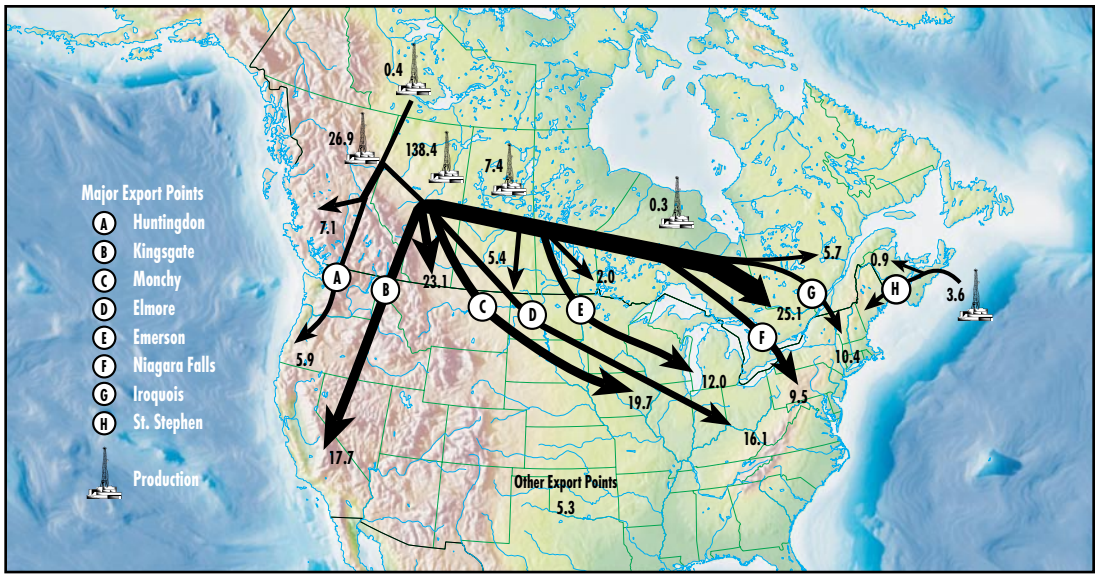
To assess the extent to which these outcomes are achieved, the Board uses publicly available data for Group 1 regulated companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company.[3] These companies represent the major NEB-regulated pipelines and provide a good view of the overall functioning of the hydrocarbon transportation system. In addition, the Board used throughput and capacity information received from the pipelines; discussions with members of the investment community; and input from the users of NEB-regulated pipelines. Although the majority of information presented in this report is an update and assessment for 2006; where available, 2007 information is also provided. A listing of the companies regulated by the NEB, as of December 31, 2006, can be found in Appendix 2.

This report should not be viewed as a regulatory decision. In this report the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. The factors used to assess the functioning of the transportation system are not necessarily the same as those which are applied in a regulatory proceeding.

Figures 3 and 4 provide an overview of the supply and disposition of natural gas and crude oil in Canada. More information on the supply and disposition of energy in Canada can be found in the Board's Energy Overview report, published in May 2007, which may be found at http://www.neb-one.gc.ca/energy/EnergyReports/index_e.htm#energy_overview.

FIGURE 3

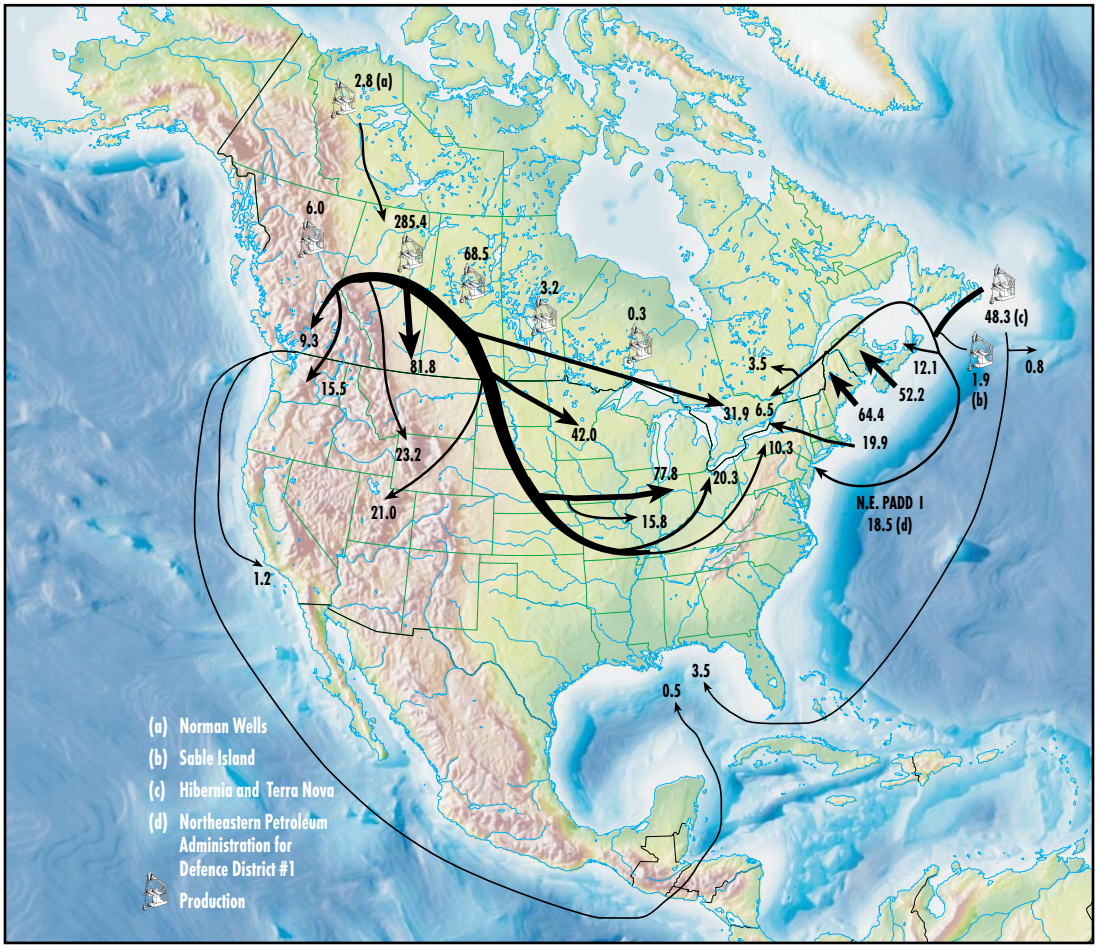
2006 Supply and Disposition of Natural Gas (Billion Cubic Metres)



3 For the purpose of the Board's financial regulation, pipeline companies are divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are generally actively regulated by the NEB. All other NEB-regulated pipelines are designated as Group 2 and are subject to a lighter degree of regulation.

FIGURE 4

2006 Supply and Disposition of Oil
(Thousand cubic Metres per Day)



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ADEQUACY OF PIPELINE CAPACITY

A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and natural gas liquids (NGLs) from producing to consuming regions.

This section will examine the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is desirable. This may result in higher tolls for shippers; however, the costs associated with inadequate pipeline capacity can be far greater. Substantial revenue loss for producers and governments can result when producers are unable to move their oil and gas to market. In addition, excess capacity allows shippers the flexibility to access the appropriate markets with the right product, thereby maximizing their revenues.

For example, in the case of oil transportation, if there is inadequate pipeline capacity to transport crude oil to the West Coast (PADD V), producers have the option of transporting crude oil to Ontario, PADD II (Midwest), southern PADD II (Cushing, Oklahoma), PADD III (U.S. Gulf Coast) or PADD IV (Rockies). As well, during periods when refineries are in turnaround (maintenance) in any of these locations, producers can deliver crude oil volumes to other markets, providing there is adequate pipeline capacity.

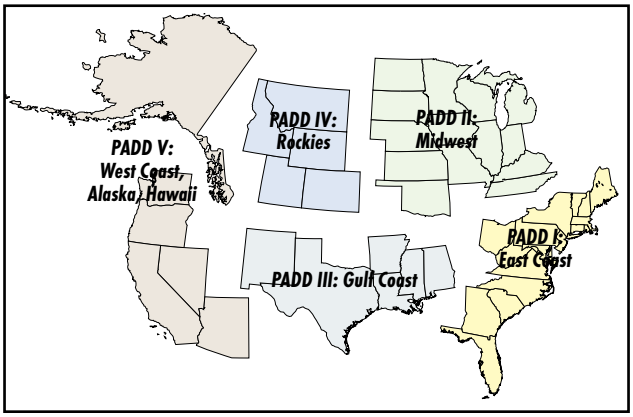
2.1 Price Differentials

Price Differentials and Natural Gas Firm Service Tolls

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. In a market with adequate capacity, suppliers would generally direct their product to the

FIGURE 5

Petroleum Administration for Defense Districts



market that nets the highest revenue back to the seller, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market, resulting in higher prices for downstream consumers or lower prices to producers, creating a higher differential in price between the two end points.

In order to use price differentials as an indicator on the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited Mainline (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

Figure 6 shows the basis differential between Alberta and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The price differential between Alberta and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in the price difference between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. Times of exceptional natural gas demand in eastern markets, such as the summer heat waves of 2005 and 2006 that produced a strong demand for natural gas-fired power generation for air conditioning in eastern markets, or reduced supplies from the Gulf of Mexico in the months following hurricanes Katrina and Rita (August 2005 to January 2006), have resulted in short term increases in the price differential. Conversely, mild weather and ample gas in storage can moderate the price differential and the demand for gas and transportation services such as occurred in the autumn of 2006 and the early part of the 2006/2007 winter heating season.

Figure 7 shows the price differential between Compressor Station 2 on the Westcoast system and the export point at Huntingdon/Sumas compared with the firm service toll for transportation between the two locations (T-South or Southern Mainline), including fuel costs. Since January 2003, except for the peak winter months in recent years, the price differential has been lower than the cost of transportation, indicating that there has been adequate capacity in place. Overall, the comparison of price differential and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. However, natural gas pricing is volatile. Short-term increases in the price differential have been observed in recent years as a result of changes to market conditions such as,

FIGURE 6

Dawn – Alberta Price Differential vs. TransCanada Toll and Fuel

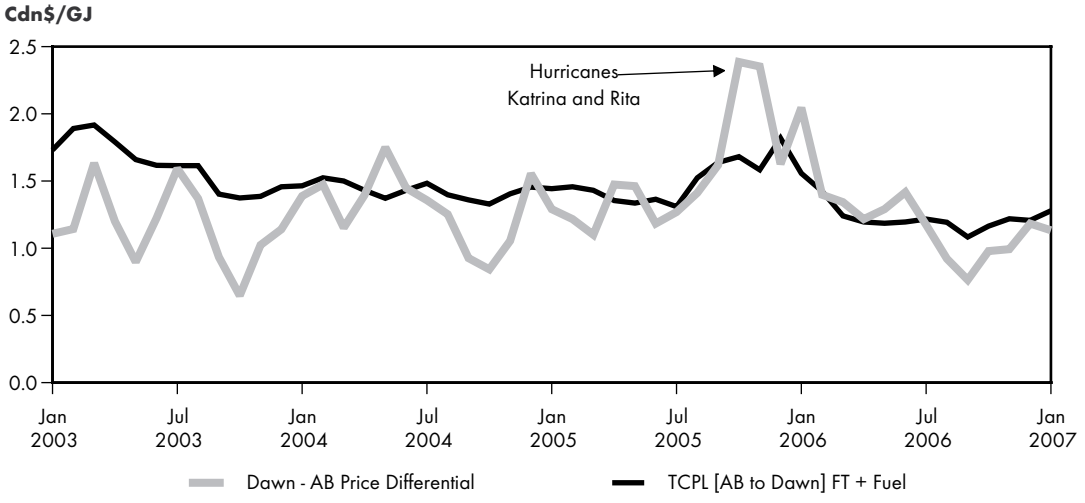
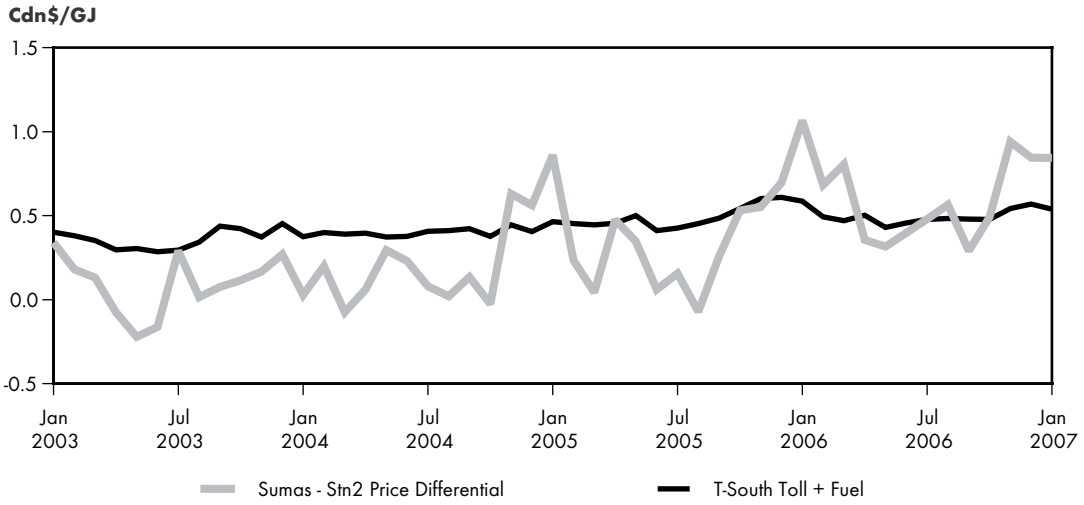


FIGURE 7

Sumas – Station 2 Price Differential vs. Westcoast T-South Toll and Fuel



hurricane-induced supply disruptions in the United States, unpredictable weather-related demand, and availability of other transportation options during such periods.

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the price differential between pricing points has been slightly lower than the cost of pipeline transportation (tolls) and fuel. However, natural gas prices can fluctuate in response to weather and can impact both price differential and pipeline fuel costs. Pipeline tolls tend to be more constant. Figures 6 and 7 both indicate occasions where the price differential exceeded transportation (toll) and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

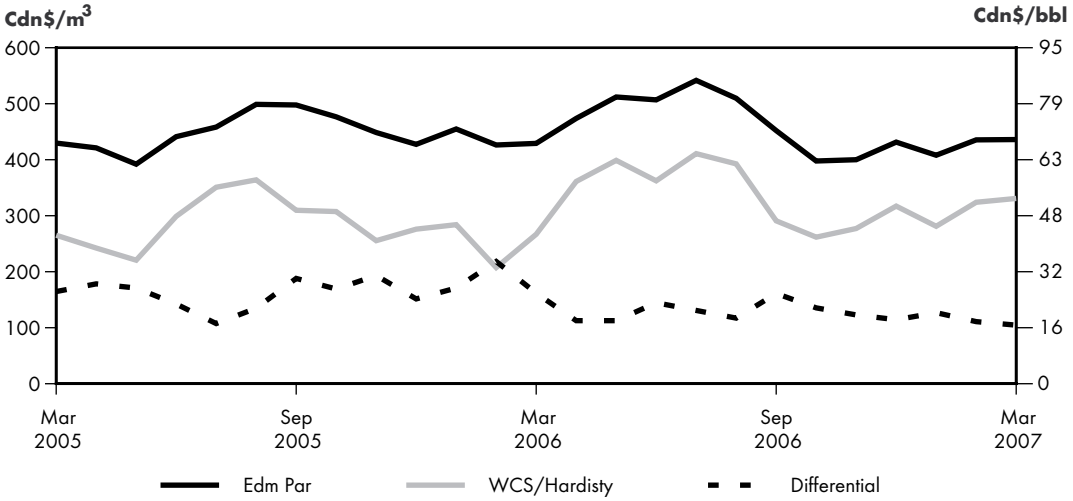
Price Differentials and Tolls on Oil Pipelines

The price differentials for crude oil are determined by a number of factors, including availability of pipeline capacity, supply and demand fundamentals, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of increasing production from the oil sands. Oil sands crude oil is a heavier bitumen blend and has limited market access because it requires specially equipped refineries to process it into useable refined products. This limited access exerts downward pressure on heavy crude oil prices and widens the light-heavy differential during certain times of the year. Historically the discussion on price differentials have been exclusive to heavy crude oil; however, with increased production of upgraded bitumen or light synthetic crude oil - the price differential between synthetic crude oil, Canadian light crude oil, and other crude oil supplied to U.S. refineries is becoming an increasingly important issue. Largely as a result of increased synthetic crude oil production and limited pipeline capacity to downstream markets, price discounts have also been observed for Canadian synthetic and light crude oil.

Figure 8 illustrates the light-heavy differential as indicated by the difference in the price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil blend that is priced at Hardisty, Alberta. As illustrated, the differential between them has been wide and volatile during the time period shown; however, there has been a narrowing trend since September 2006. In the first quarter 2007, the light-heavy differential was 27 percent. In particular, in the month of March, the light-heavy differential narrowed to its lowest level since August 2004. There are two main reasons

FIGURE 8

Canadian Crude Oil Prices and Differential



for this narrowing; one is the Syncrude upgrader expansion, which is processing more bitumen, up to 350 Mb/d per day from 240 Mb/d in 2006; the second is the Spearhead and Mobil pipeline reversals which are transporting almost 200 Mb/d of crude oil south of Chicago to as far as the U.S. Gulf Coast. Typically, during the summer months, the differential narrows because of an increase in seasonal demand for heavier crudes for the production of asphalt.

2.2 Capacity Utilization on Major Routes

Where adequate pricing data is not available at major receipt and delivery locations on pipeline systems, another measure of adequate capacity comes from directly comparing the throughput or flow on the pipeline with its capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

Natural Gas

Figure 9 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. This comparison illustrates that there has consistently been capacity in excess of throughput volumes over the time period shown. The excess capacity even persisted through the period of July 2005 to July 2006, which included two hotter-than-normal summers that produced strong demand for natural gas for power generation in eastern markets, and greater demand for Canadian gas due to production losses in the U.S. stemming from the late summer hurricanes of 2005.

On the eastern part of the TransCanada system, a number of expansions occurred in 2006 or are proposed for 2007 which are directed towards reducing bottlenecks to connect additional supply from Dawn and to access growing markets in Eastern Canada and the U.S. Northeast.

Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets. Excess capacity, which averaged 1.4 Bcf/d over the past four years, provided the impetus for the TransCanada Keystone Pipeline project. In this initiative, TransCanada proposes to transfer Line 100-1 of the Mainline to TransCanada Keystone Pipeline GP Ltd. for conversion to oil service. This transfer and conversion, if approved, could result in an annual average capacity reduction on the Mainline of approximately 0.5 Bcf/d. The Board approved the facilities transfer on 9 February 2007, however the TransCanada Keystone application for the construction of the requested oil facilities is still before the Board.

The volumes shown in Figure 10 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline transports western Canadian gas supply to

FIGURE 9

TransCanada Mainline Throughput vs. Capacity

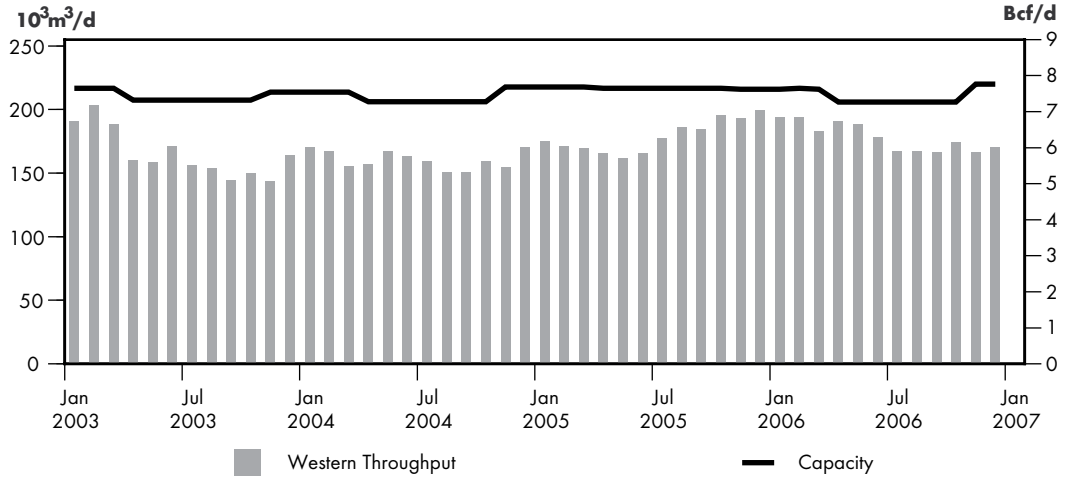
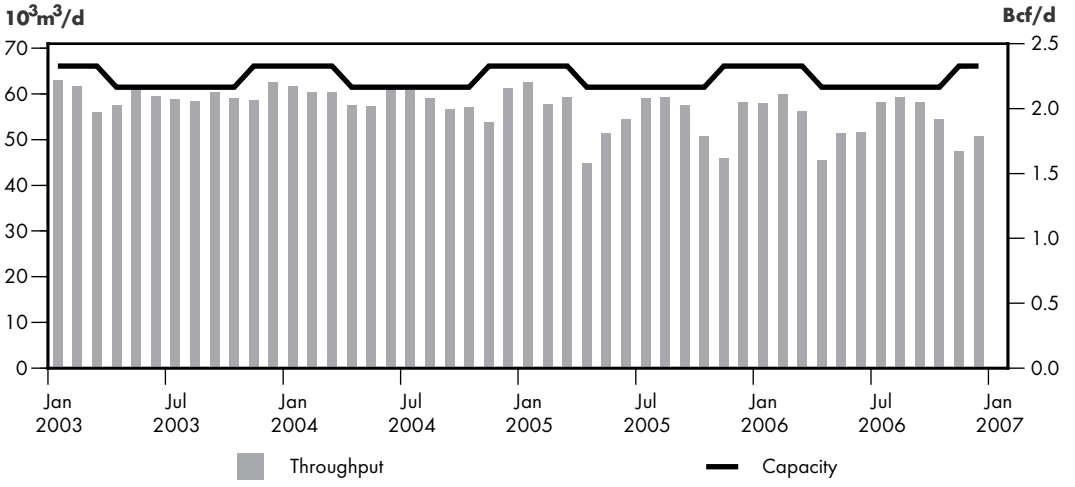


FIGURE 10

Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy



markets in the U.S. Midwest through a connection with the Northern Border Pipeline Ltd. (Northern Border) at Monchy, Saskatchewan. The Foothills (Sask.) throughput has displayed distinct seasonal patterns in recent years, with annual average capacity utilization running at 88 percent in 2006, down from an average of 94 percent in 2003. Throughput on the Foothills Pipeline (Sask.) runs fairly close to capacity in both the winter and the summer months to meet winter heating demand and to meet summer demand for power generation and storage injection. Throughput subsequently declines in the low-consumption spring and autumn months.

Figure 11 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the export point at Huntingdon/Sumas. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. Contributing factors to the low flows on Westcoast during 2006 and recent years include greater competition with production from the U.S. Rockies region for markets in the U.S. Pacific Northwest, mild winter weather, and increased hydro power generation in B.C. and the U.S. Pacific Northwest.

Figure 12 shows the average monthly capacity and throughput on the TransCanada B.C. System, which primarily serves California. The annual average capacity utilization in 2006 was 64 percent, slightly higher than in previous years. There exists spare capacity on this pipeline to export gas through Kingsgate, B.C. California market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB). This supply competition has reduced imports from the WCSB at Kingsgate.

Figure 13 shows the average monthly throughput on the Alliance system relative to physically available capacity. Alliance offers approximately 1.325 Bcf/d of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

FIGURE 11

Westcoast Mainline Throughput vs. Capacity

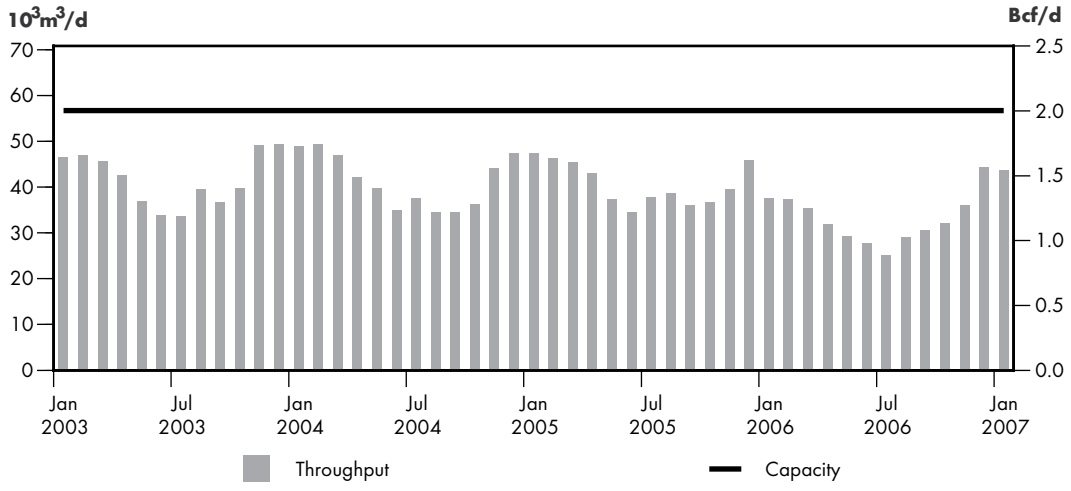


Figure 14 compares the average monthly throughput and capacity on the TransQuébec & Maritimes system (TQM) which delivers gas from the TransCanada Mainline at Saint-Lazare, Quebec to Québec City and the East Hereford export point in Quebec (New Hampshire state border). More volumes are transported during winter months, highlighting the use of natural gas for heating in this region and the seasonal nature of the throughput on this pipeline. With average annual capacity utilization of around 60 percent, there has historically been spare capacity on this pipeline, particularly in summer months. However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution on the pipeline. In 2006, TQM undertook a system expansion to serve an incremental demand arising from the construction of a new gas-fired power plant in Quebec.

Figure 15 compares the average monthly capacity and throughput on the M&NP pipeline. The annual average capacity utilization has declined from about 92 percent in 2002 to an average of about 68 percent in 2006. The reduction in this pipeline's capacity utilization stems from declining natural

FIGURE 12

TransCanada B.C. system Throughput vs. Capacity at Kingsgate

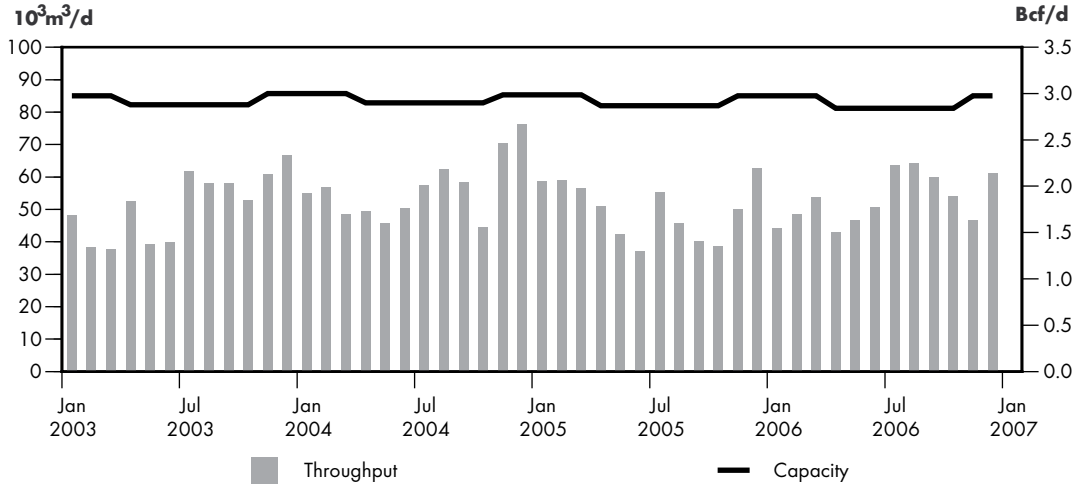


FIGURE 13

Alliance Throughput vs. Capacity

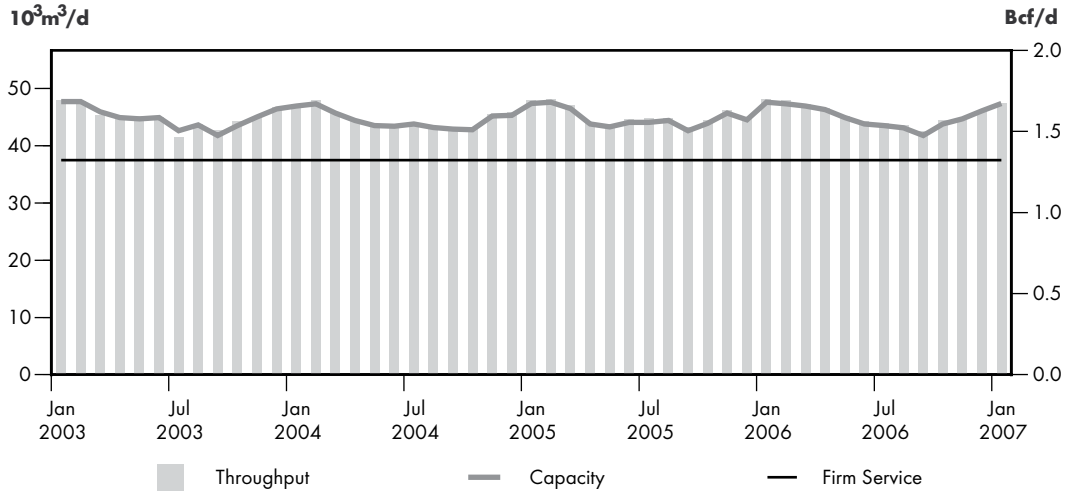


FIGURE 14

Trans Québec and Maritimes Throughput vs. Capacity

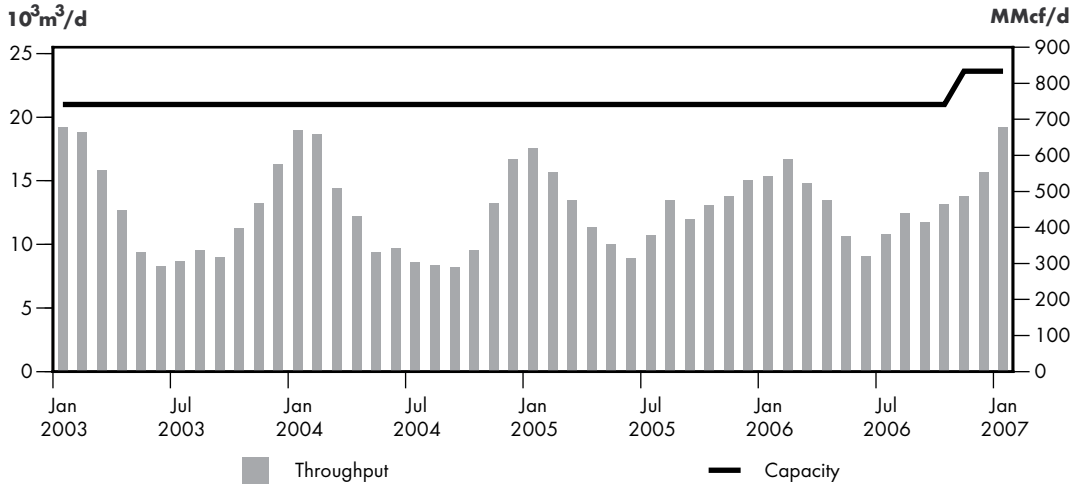
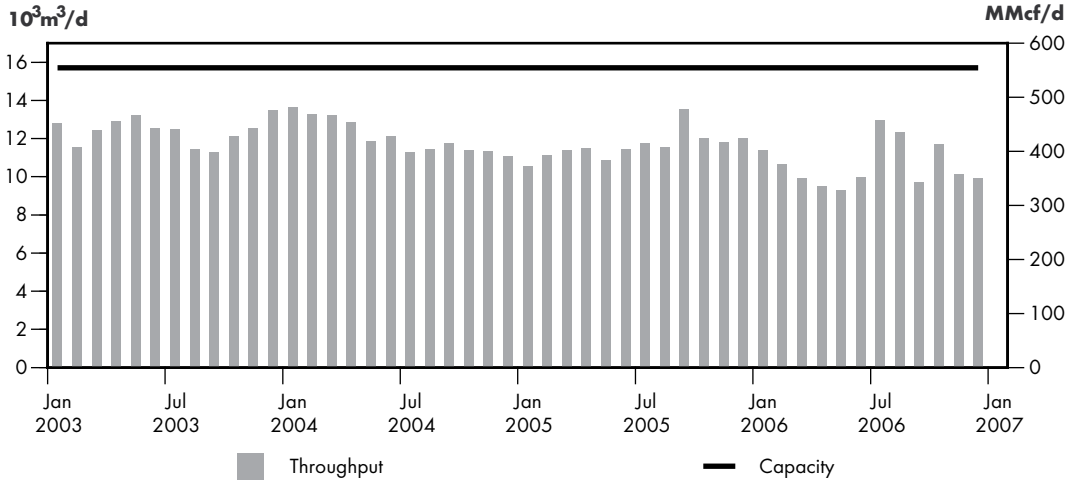


FIGURE 15

Maritimes and Northeast Pipeline Throughput vs. Capacity



gas production from offshore Nova Scotia. Variations in throughput are primarily related to changes in gas supply as the export demand for gas destined to northeastern U.S. markets is consistently strong. In late 2006, additional compression at the offshore platform was installed to boost deliverability. In addition, a couple of gas supply projects are being considered in the region with the potential to supplement supply.

Oil

Determining the capacity and throughput on an oil pipeline can be complex as there are many factors to be considered: the type of product, product mix, type of batching and pipeline configurations.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba where it joins with the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The Enbridge system also connects

with pipelines that deliver crude oil to Cushing, Oklahoma and the U.S. Gulf Coast. The system consists of many lines transporting crude oil, NGLs and refined petroleum products. Figure 16 illustrates Enbridge throughput versus capacity. In 2006, Enbridge transported roughly 247 000 m^3/d (1.6 MMb/d) of crude oil, petroleum products and NGLs. In the first quarter 2007, Enbridge operated at about 85 percent of capacity. Since the third quarter of 2006, many of its lines have been operating at or near full capacity with some lines in apportionment (see Section 2.3).

Terasen Pipelines (Trans Mountain) Inc., owned by Kinder Morgan, transports crude oil and refined petroleum products from Edmonton, Alberta west to locations in British Columbia, Washington State and offshore. TPTM's current capacity, assuming some heavy crude oil, is 35 700 m^3/d (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (See Section 2.3). Figure 17 shows two capacities for the TPTM pipeline; one assumes no shipments of heavy crude oil and the other assumes 15 percent heavy crude oil. When heavy crude oil is shipped, it reduces the capacity of the pipeline. On average, in 2006, 15 percent of TPTM's crude oil receipts at Edmonton were heavy crude oil. In the second quarter of 2007, the TPTM Pump Station Expansion is expected to be in-service. It will add an additional 5 600 m^3/d (35 Mb/d) of capacity.

In February 2006, TPTM applied to the NEB to loop a 158 km segment of its pipeline, extending from Hinton, Alberta to a location near Rearguard, British Columbia. The Project would increase capacity by 6 360 m^3/d (40 Mb/d). An oral public hearing was held in August 2006 and the Board approved the application in October. The targeted in-service date is the fourth quarter 2008.

In the first quarter of 2007, TPTM operated at approximately 77 percent of capacity (see Figure 17). Despite operating at below its nameplate capacity of 285 Mb/d, TPTM was under apportionment in January and February of 2007. Growing oil sands production, strong demand from refiners in Washington State and continuing growth in crude oil shipments off the Westridge Dock are contributing to apportionment on the TPTM system. As well, in the summer of 2006, a temporary shutdown of the Prudhoe Bay field in Alaska, because of pipeline corrosion, resulted in increased throughput on the TPTM pipeline.

During the past several years, Express has been operating at capacity. Despite a major expansion in 2005 that added 16 000 m^3/d (100 Mb/d), bringing the capacity to 44 900 m^3/d (280 Mb/d) there has

FIGURE 16

Enbridge Pipeline Throughput vs. Capacity

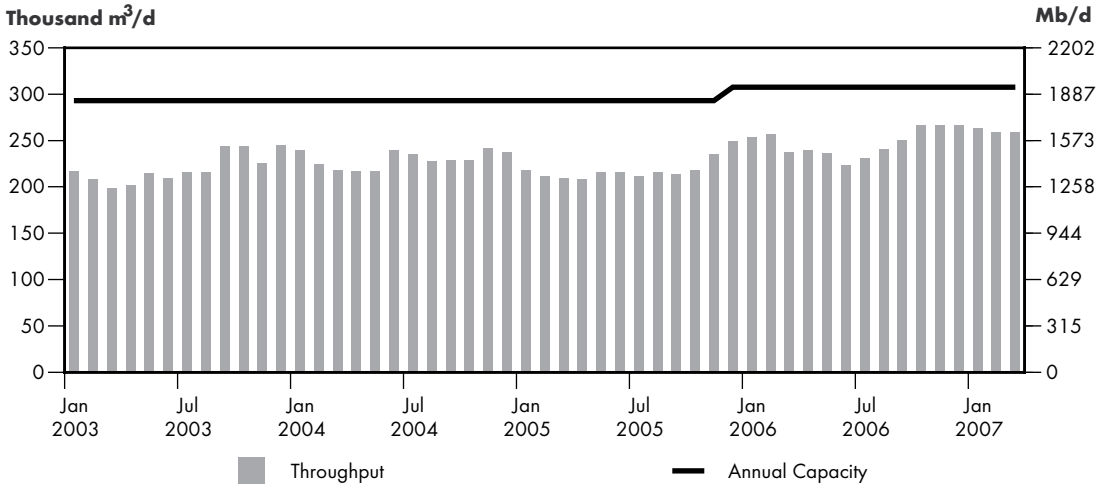


FIGURE 17

Teresen Pipelines Trans Mountain (TPTM) Throughput vs. Capacity

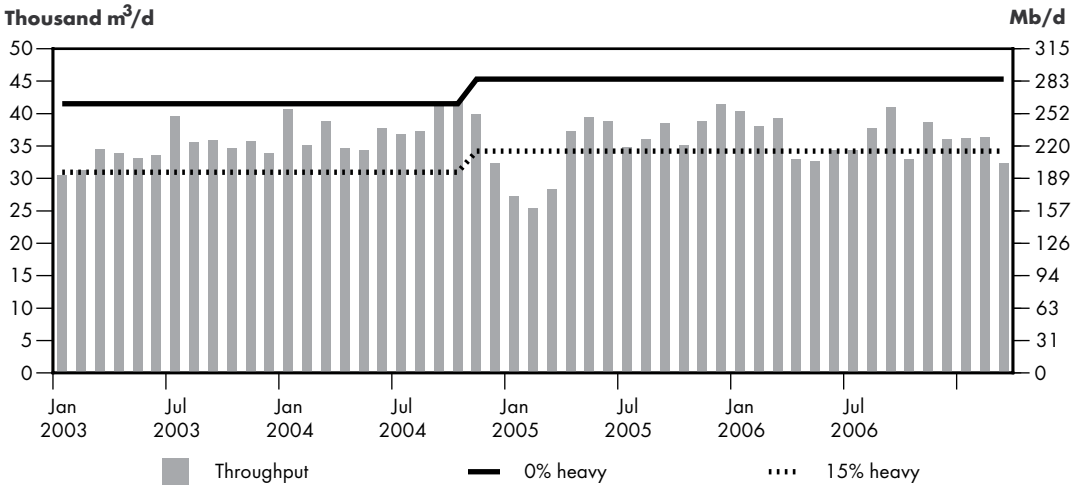
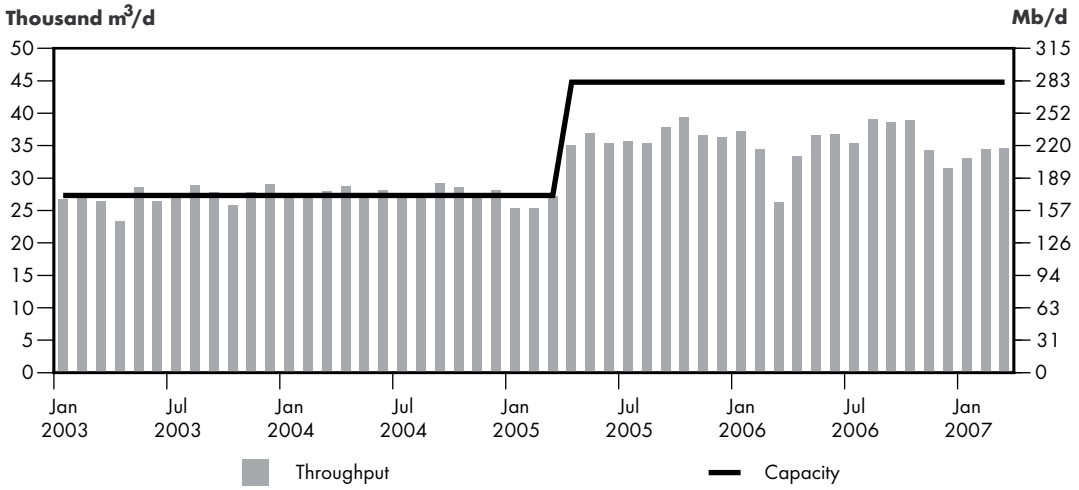


FIGURE 18

Express Throughput vs. Capacity



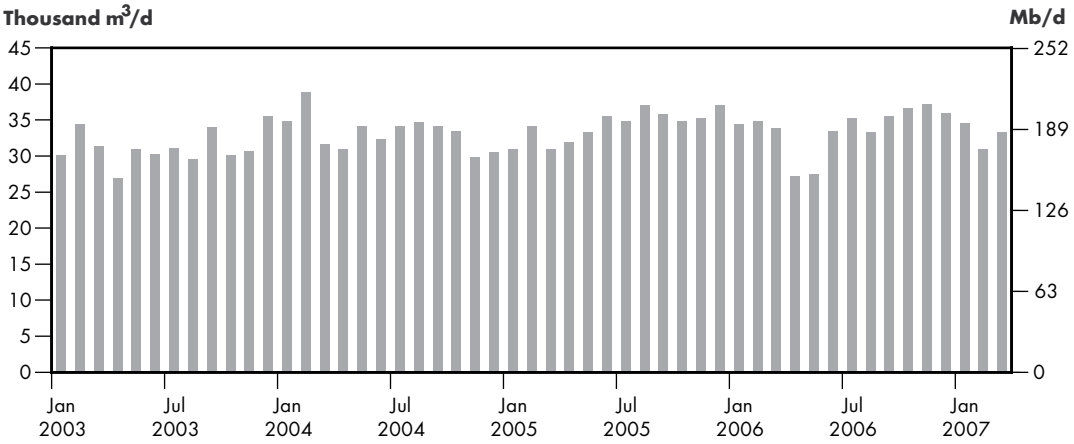
been apportionment on the pipeline in 2006. Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for a majority of its capacity.

In the first quarter 2007, Express operated at approximately 76 percent of capacity (Figure 18). Crude oil shipments have been reduced at Hardisty on the Express pipeline because of continuing apportionment downstream on the Platte Pipeline in the U.S.

Trans-Northern Pipelines Inc. is a refined petroleum products pipeline. The pipeline transports refined petroleum products west from Montreal to north Toronto and operates bi-directionally between Toronto and Oakville, Ontario. TNPI also transports refined products from Imperial Oil Limited's (Imperial) refinery in Nanticoke, Ontario west to Toronto. In the first quarter of 2007, TNPI throughput averaged 33 000 m^3/d (208 Mb/d) of petroleum products. The pipeline is generally operating at capacity.

FIGURE 19

Trans-Northern Pipelines Inc. Throughput



During the first quarter 2007, there was a fire at Imperial's refinery located in Nanticoke. This resulted in the refinery ceasing operations and a subsequent gasoline and diesel shortage in southern Ontario and Quebec. TNPI throughput was reduced during this period.

Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

2.3 Apportionment

Oil pipelines typically operate as common carriers. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for pipeline capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. There are a few pipelines in Canada that operate all or part of the pipeline with long-term shipper take-or-pay agreements, including Express, Enbridge Line 9 and TNPI.

Some recent apportionment levels for Enbridge, TPTM and Cochin are discussed below.

Enbridge

Enbridge's Lines 3 and 4 are dedicated to transporting heavy crude oil and Line 2 transports light crude oil. Historically, Lines 2 and 4 were heavy crude oil lines; however, following the Line 2/3 line swap in the fourth quarter 2005, Line 2 transitioned from a heavy crude oil line originating at Hardisty, Alberta to a light crude oil pipeline originating in Edmonton. In addition, Line 3 made the transition from a light crude oil pipeline originating at Edmonton to a heavy crude oil pipeline originating at Hardisty. This swap resulted in a net heavy capacity increase of 39 000 m^3/d (246 Mb/d) and a corresponding decrease of light capacity of 18 400 m^3/d (116 Mb/d). This added some much needed capacity to accommodate growing heavy crude oil output from the oil sands.

Table 1 indicates apportionment and throughput from August 2006 to March 2007. In the fourth quarter 2006, throughputs were very high on the Enbridge system and there was apportionment on Lines 5, 6 and 14. There has not been apportionment on the Enbridge system in the first quarter 2007; however, many of the Lines have been either fully subscribed or operating at maximum capacity.

TABLE 1

Enbridge Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment	0%	0%	0%	0%	8%*	0%	0%	0%
Throughput (10^3m^3/d)	240.7	251.0	266.3	266.8	266.7	263.6	258.9	259.7

* Lines 5, 6 and 14

Capacity is also constrained due to a downstream bottleneck at Superior, Wisconsin because the capacity out of Superior is 230 000 m^3/d (1.4 MMb/d), less than the up to 300 000 m^3/d (1.9 MMb/d) that Enbridge can deliver to that destination.

Enbridge throughput fell slightly in the second quarter 2006 as a result of outages at two oil sands plants. In the third quarter 2006, throughput increased reflecting capacity expansions and increases in oil sands production. In addition, competitively priced western Canadian crude oil displaced some import volumes that would typically be delivered to the Sarnia area on Enbridge's Line 9. It is expected that increasing production from the oil sands in 2007 could contribute to further apportionment on Enbridge.

Enbridge's Line 9 has a capacity of 38 150 m^3/d (240 Mb/d) and transports crude oil from Montreal, Quebec to refineries located at Nanticoke and Sarnia, Ontario. There was no apportionment on Line 9 between August 2006 and February 2007. Shipments on Line 9 have been trending downward, particularly since the closure of Petro-Canada's refinery in Oakville in the second quarter of 2005. In 2006, the reduction in throughput was a result of maintenance activity at Imperial's Sarnia refinery in the second quarter and an increase in deliveries of more competitively priced western Canadian crude oil.

In January 2007, Enbridge Pipelines (Westspur) Inc. applied to the National Energy Board pursuant to section 52 of the *National Energy Board Act* (NEB Act), for the Alida, Saskatchewan to Cromer, Manitoba Capacity Expansion Project. The Enbridge Westspur pipeline was built in 1956 as an oil trunkline to transport crude oil. The pipeline also transports NGL from a gas processing plant in Steelman, Saskatchewan. Westspur interconnects with the Enbridge export lines at Cromer where the crude oil accesses the downstream markets.

The project proposes to construct a new 60 km, 168.3 mm (6 inch) pipeline to transport NGL from Alida to Cromer and convert the existing pipeline from its current NGL service to crude oil. Capacity on the existing line would increase from 25 000 m^3/d (157 Mb/d) to 34 600 m^3/d (218 Mb/d)

Terasen Pipelines (Trans Mountain) Inc.

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment between August 2006 and March 2007 reflects continuing increases in oil sands supply and strong demand for Canadian crude oil in the Washington State area. In addition, increases in heavy crude oil shipments, result in a decrease in the capacity on the TPTM system. With weakness in the price of West Texas Intermediate (WTI) and discounting of Canadian crude oil because of over-supply in the Cushing area, coupled with a lack of take away capacity in that region, producers may increasingly look to the higher priced west coast and offshore markets for improved netbacks.

TABLE 2

TPTM Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment								
Domestic	0%	8%	0%	14%	35%	22%	10%	0%
Export	0%	0%	0%	0%	12%	0%	0%	0%
Dock	0%	0%	0%	0%	0%	0%	0%	0%
Throughput ($10^3m^3/d$)	37.6	41.0	32.9	38.6	35.9	36.2	36.3	32.4

In April 2006, the NEB approved a request from Kinder Morgan Inc. to include a Westridge Dock Premium in the TPTM tariff to allocate capacity to the Westridge Dock. In the Board's decision, it directed Kinder Morgan to set up a deferral account for any premiums received and refund the money to toll payers in the following calendar year. The Board directed Kinder Morgan to publish the aggregate bid premium information on a quarterly basis; and, it approved the extension of the bid premium process until the start-up of the pump station expansion (PSE).

Cochin

In January 2007, Kinder Morgan Energy Partners purchased the remaining approximately 50 percent of Cochin Pipeline that they did not already own from BP Canada Energy Company (BP). Prior to the purchase, BP operated the pipeline and owned a slight majority stake.

The Cochin pipeline is the largest and longest NGL pipeline in Canada. In the past, it has transported propane, ethane, ethylene and butane, although no butane has been shipped since 2002. Ongoing maintenance work on the pipeline has affected the available capacity; however, (Table 3) there has not been apportionment on Cochin since summer 2005 when the pipeline was forced to unexpectedly shutdown for immediate repairs.

Since March 2006, Cochin has operated at a voluntary pressure reduction due to a defect found in the U.S. portion of the pipeline. This pressure restriction, not to exceed 900 psi, applies to the entire line from Fort Saskatchewan, Alberta to Windsor, Ontario and is in effect through at least to the fall of 2007. Ethylene shipments, because of its high vapour pressure, have been suspended until further notice.

Cochin also announced on 8 February 2007 that it would be suspending delivery of ethane effective 31 March 2007, while the company evaluates its pipeline integrity issues and the related capital expenditures. Cochin will continue to ship propane to all destinations on its system. Shippers were also informed that the pipeline would operate at reduced pressure through at least Fall 2007. With only propane in the line, the average capacity is expected to be around 9 500 to 11 100 m^3/d (60 Mb/d to 75 Mb/d). Once the pressure restrictions are lifted, capacity is likely to return to 16 700 m^3/d (105 Mb/d).

TABLE 3

Cochin Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment	0%	0%	0%	0%	0%	0%	0%	0%
Throughput ($10^3m^3/d$)	7.6	5.6	9.5	7.6	10.9	7.7	7.4	6.5

2.4 Chapter Summary

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines in section 2.2 shows that pipeline capacity is adequate across the country although there may be occasions of short-term limitation at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas and utilization of some Canadian pipelines can be variable. Where available, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently and at more stable utilization levels.

Although natural gas supply from new sources continue to be added to supplement declining conventional supply from the WCSB, growing demand within Western Canada has resulted in some excess capacity on pipelines transporting gas from the region. The existence of some excess capacity has provided suppliers with the flexibility to access markets of their choice at most times. Natural gas pipeline projects in 2006 were mainly directed towards providing connection to new supplies and addressing bottlenecks in the market area.

While capacity utilization indicators show that there was spare capacity on some oil and petroleum products pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. Despite operational challenges in the oil sands industry in early 2006, bitumen production levels have increased over the previous year as problems were rectified and new expansions were brought on-line. The production growth in the oil sands and continued strong demand in the U.S. has resulted in very high utilization of capacity on Canadian oil pipelines. In addition, a slight recovery in conventional crude oil production in western Canada, North Dakota and PADD IV are challenging pipeline systems that operate at close to capacity and are in apportionment at times. Overall, growing oil sands production has kept the utilization and demand for oil pipeline capacity very high.

In the past, the lack of excess pipeline capacity and available markets to process heavier crude oil has resulted in the light-heavy price differential widening as illustrated in Figure 8. In the first quarter 2006, the differential widened to 42 percent. However, this has not been the case in 2007, where the differential has narrowed to a two and a half year low reflecting the effect of additional markets accessed through the Syncrude upgrader expansion and the Spearhead and Mobil pipeline reversals which deliver western Canadian crude oil to Cushing and the U.S. Gulf Coast, respectively. This should provide continuing strength to heavy crude oil prices through the summer as demand will increase in response to the upcoming asphalt season.

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Attachment 13

LOOKING AHEAD – PROPOSED PIPELINES

3.1 Natural Gas

In the coming years, it is expected that demand for natural gas in North America will continue to outpace the growth in North American domestic supplies. In Canada, natural gas supply from new sources such as frontier regions, LNG, and coalbed methane will be increasingly required to supplement declining supply from conventional sources from the WCSB and Sable Island to meet growing demand. In addition, increased consumption for oil sands development in Alberta, and electricity generation in Ontario, are expected to drive significant incremental Canadian requirements for natural gas. The Canadian oil sands projects are a large and growing market for natural gas in both the generation of electricity and steam. Steam is used for in situ oil production and to upgrade bitumen into synthetic blends. In addition, new gas-fired electrical generation will likely be needed to help displace the use of existing coal-fired electricity generation in Ontario.

Although there were few newly announced natural gas pipeline projects in 2006, there was notable progress in several of the natural gas pipeline projects reported last year. Table 4 below, summarizes the announced proposals on NEB-regulated pipelines. These projects reflect the industry's expectations regarding changes in natural gas supply and demand in coming years, and the industry's outlook on the potential adjustments in Canadian pipeline infrastructure in order to:

- connect incremental gas supply from new sources in the north or from new terminals for receiving liquefied natural gas;
- expand pipeline capacity to growing markets in eastern Canada and the U.S. Northeast; and
- transfer pipeline assets from gas service where adequate capacity may exist, to oil transportation service where demand and value for new capacity is higher.

Liquefied Natural Gas

A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. While economies of scale advances in liquefaction and transportation have enabled the use of LNG as a cost competitive source of gas supply in North America, those cost efficiencies are starting to be lost to higher input and construction costs. In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing U.S. terminals and construct new LNG receiving facilities, including several proposed projects in Canada as summarized in Figure 20.

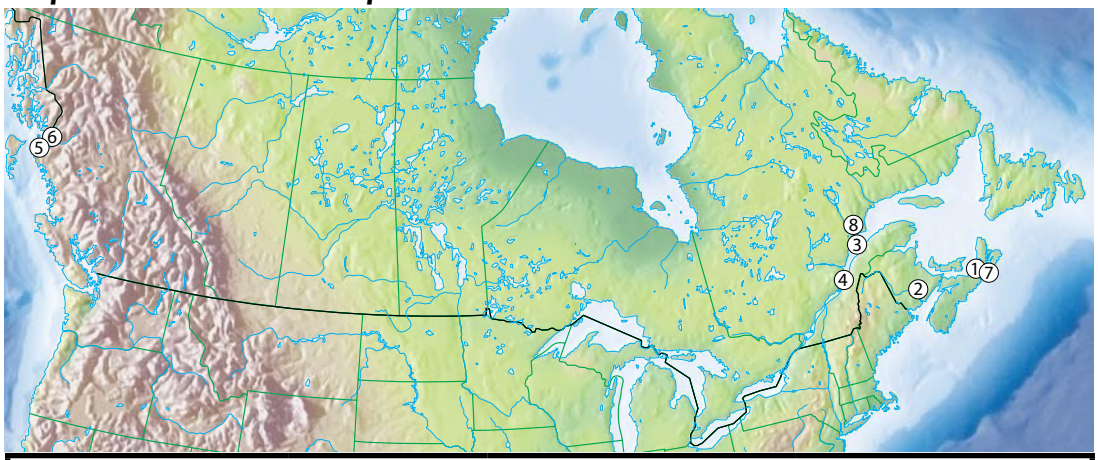
TABLE 4

Canadian Natural Gas Pipeline Proposals — 2006

Pipeline	Location	Capacity Increase (Bcf/d)	Proponents' Estimated Completion Date	Market Impacted
TransCanada PipeLines Limited – 2007 Eastern Mainline Expansion	Ontario, Québec	0.377	Late 2007	Central Canada Northeastern U.S.
TransCanada Pipelines Limited and TransCanada Keystone GP Ltd.	Saskatchewan, Manitoba	-0.5	2009/10	Transfer and conversion of gas pipeline assets to oil transportation service
Mackenzie Gas Pipeline	Mackenzie Delta, Northwest Territories to Alberta	1.2	2014	North America
Emera Brunswick Pipeline	New Brunswick	0 .75	2008	Atlantic Canada, Northeastern U.S.
EnCana – Deep Panuke Pipeline	Nova Scotia	0 .3	2010	Atlantic Canada, Northeastern U.S.
TransCanada PipeLines Limited / Trans Québec & Maritimes Pipeline Inc. – Gros Cacouna and Rabaska	Québec	0.5 0.5	2009/10	Central Canada Northeastern U.S.

FIGURE 20

Proposed Canadian LNG Projects



Location	Terminal	Company	Capacity (Bcf/d)	Proposed on Stream Date
1. Goldboro, Nova Scotia	Maple LNG	4 Gas BV and Suntera Canada Ltd.	1.0	2009
2. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	0.8	2008
3. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2009
4. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2009
5. Ridley Island, British Columbia	WestPac LNG	WestPac Terminals Inc.	0.3	2009
6. Emsley Cove, British Columbia	Kitimat LNG	Gavelston Energy	0.6	2010/11
7. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
8. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	n/a

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. The Canaport LNG facility in Saint John, New Brunswick is currently under construction and is scheduled to start service in 2008. Additional pipeline connections will also be required in most cases to connect the proposed LNG receiving terminals to existing natural gas pipeline infrastructure and natural gas markets.

These potential changes in Canada's natural gas supply and demand have important implications to both existing pipeline transportation systems and proposed new pipeline and LNG projects. Facilities which connect significant new supply from new sources such as the North and LNG or significant changes in regional demand (e.g. oil sands in Alberta and electricity generation in Ontario) will have the potential to influence markets and alter the utilization and gas flow on existing pipelines. In turn, these changes may impact the tolls and associated costs in using those pipelines. For example, introduction of new gas supply in Eastern Canada could result in greater utilization or flow reversals in regional pipelines and may also affect the flow of supply from traditional sources and pipelines. Similarly, greater demand in Alberta or Ontario can also alter the flow and availability of natural gas to adjacent regions.

In addition, the expected introduction of LNG close to Canadian markets has heightened the awareness of potential issues related to gas quality. Consequently, pipelines will need to work closely with their customers to establish gas quality standards and monitoring processes to ensure compatibility with existing equipment and end-use operation.

3.2 Oil

The expected growth in oil sands production is an increasingly important consideration to the pipeline industry as it determines which incremental markets to serve and how to expand the pipeline system efficiently since not all refineries are able to process a full range of crude oil types. Proposed refinery expansions and new construction in eastern Canadian are located close to the major petroleum product markets in the U.S. Northeast and have access to foreign crude oil supplies in addition to east coast offshore production. Other refineries in central Canada and the United States are proposing modifications which will enable them to process the heavier crude oil from oil sands production.

Looking to the future, the NEB expects that Canadian crude oil production will continue to increase, placing greater demands for transportation capacity to connect new supply and markets. Consequently, there are a number of proposals to provide additional pipeline capacity to transport crude oil and to provide additional supplies of diluent required to support growing oil sands operations. This additional pipeline capacity could enhance access to markets and increase market penetration. The North American demand for oil and refined products is also expected to increase, triggering a number of proposals for refinery expansions and the construction of new refineries in Canada and in the United States.

Table 5 provides a summary of the numerous proposals to expand or construct new oil pipeline capacity in Canada. These reflect the industry's outlook on growing oil sands production and the need for additional pipeline capacity to enhance market access. These proposals include pipelines to transport western Canadian crude oil to the west coast for delivery to Washington State and offshore markets, to the U.S. Midwest and southern PADD II and to the U.S. Gulf Coast (PADD III), and to provide new sources of diluent required for growing oilsands production. It is estimated that these pipeline projects comprise over $23 billion in spending.

TABLE 5

Announced and Proposed Canadian Oil Pipelines and Expansions

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TPTM)				
Pump Station Expansion	Filed Feb 2006; Approved in Oct 2006	35	April 2007	PADD V
Anchor Loop – TMX1	Approved in Oct 2006	40	Nov. 2008	Offshore/Far East
Southern Option				
TMPL TMX2	N/A – Open Season unsuccessful	100	Mid 2010	PADD V
TMPL TMX3	N/A	300	2012	Offshore/Far East
Northern Option (TMX North)	N/A	400	2012 (uncertain)	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	N/A	400/150	Between 2012 and 2014	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights	Filed 9 March 2007		2010	Alberta
Diluent return line		186		PADD II
Line 2 Expansion (oil)				PADD II
Edmonton to Cromer		47		PADD II
Cromer to Clearbrook				PADD II
TCPL (Keystone)	Filed Section 52 – Dec 2006	435	4Q2009	Southern PADD II and PADD III
Expansion / Extension to Cushing, OK		155	4Q2010	
Alberta Clipper	Filed May 30 2007	450	July 2010	Southern PADD II
Expansion	N/A	350	N/A	
Altex Energy	2008	250	2012	PADD III
Enbridge Spearhead	Open Season (2 Mar -2 April 2007)	65	2009	Southern PADD II
Expansion		100	2011	
Spearhead Looping	FERC only			
Enbridge (Southern Access)	FERC only	315		Midwest/Southern PADD II
Phase I		120	2008	
Phase II		148	2009	
Phase III Extension		47	N/A	

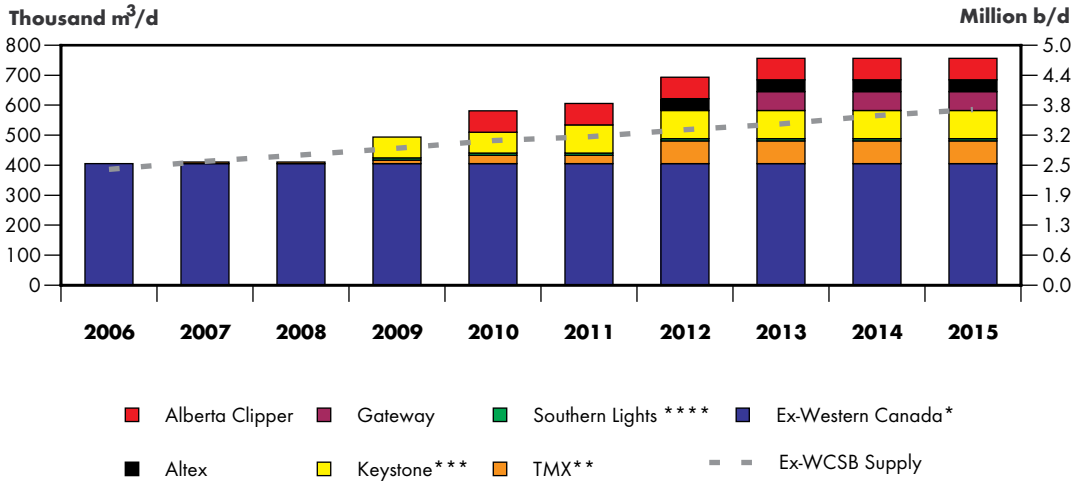
In the past year, the Board has also approved two crude oil pipeline related applications. In October 2006, the Board approved an application filed by TPTM to loop a portion of its pipeline between Hinton, Alberta and Rearguard, British Columbia. The project will increase capacity by 6 360 m^3/d (40 Mb/d). It is expected to be in service by third quarter 2008.

In June 2006, the Board received an application by TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd. to transfer a portion of TransCanada's natural gas pipeline and associated facilities to crude oil service. The Keystone Project is a proposal to convert existing natural gas facilities in Canada and to construct a new crude oil pipeline in the U.S. to transport crude oil from Hardisty, Alberta to Patoka, Illinois. It would have a capacity of 69 000 m^3/d (435 Mb/d) and is expected to be in-service in 2009 if approved. The Board approved the facilities transfer on 9 February 2007; however the TransCanada Keystone application for the construction of new oil facilities is still before the Board.

Looking beyond 2006, Figure 21 illustrates the NEB's forecast of crude oil production and the anticipated pipeline capacity available to transport crude oil and products from Western Canada on existing and proposed new facilities. This chart highlights that oil pipeline capacity is expected to be very tight in the next few years. It is expected that apportionment will occur in the fourth quarter 2007 and that this may be an issue for the next 18 months. As indicated by the figure, between now and 2009 crude oil pipelines out of Western Canada are expected to operate at capacity. The upstream industry is working together with pipeline companies to develop initiatives to reduce the impacts and/or eliminate apportionment. In 2009, TPTM would have an additional 12 000 m^3/d (75 Mb/d) of capacity with its pumping station expansion and the looping; Southern Lights could add an additional 7 500 m^3/d (47 Mb/d) to the Enbridge system from Cromer, Manitoba; and Keystone could be in-service if its application were approved by the Board.

FIGURE 21

Proposed Oil Pipeline Projects & NEB Forecast of Crude Oil Production



* Total current crude oil pipeline capacity out of the WCSB assuming maximum heavy oil volumes.

** Pump Station expansion of 35 Mb/d by 2007 and looping 40 Mb/d by 3Q2008. TMX North would expand capacity by an additional 400 Mb/d but is not shown here.

*** Keystone could be expanded by 155 Mb/d and extended to Cushing, Oklahoma by 4Q2010

**** Net crude oil capacity increase of 47 Mb/d by 4Q2008

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PIPELINE TOLLS & SHIPPER SATISFACTION

The Board utilizes a number of indicators to assess whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). This includes monitoring the stability of pipeline tolls as indicated through year-to-year variations in a benchmark toll for each of the major NEB-regulated pipelines; and direct shipper feedback received through response to the NEB's annual survey on pipeline services and via formal complaints. In addition, the frequency and acceptance of negotiated toll settlements, and the development of new or enhanced pipelines services are important indicators that there is alignment between the interest of pipeline companies and their shippers.

Historically, revenue requirements have been established using cost of service methodology, with some components for the return on and of invested capital. The revenue was then assigned to various rate categories and cost drivers for conversion into unit rates, or tolls. The revenue requirement and the toll setting methodology were matters for adjudication before the Board.

4.1 Negotiated Settlements

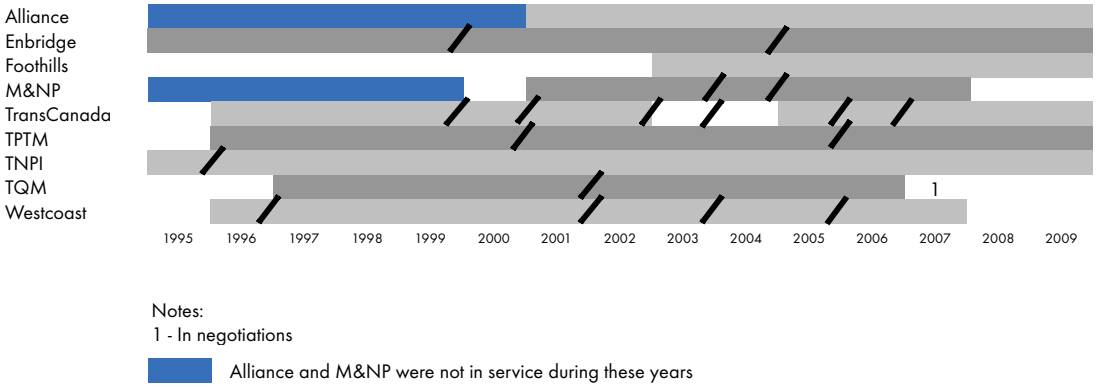
To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements since the mid-1980s as an alternative to toll hearings. In September 1988, the Board issued its first Guidelines for Negotiated Settlements. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements. With increasing use of negotiated settlements, adversarial hearings before the Board on tolls are becoming less frequent. Most of the pipeline companies still rely on cost of service methodology as a framework for the negotiated settlements.

As shown in Figure 22, all of the major pipelines regulated by the Board were operating under negotiated settlements during 2006. In late 2006, M&NP and its shippers successfully negotiated a one-year toll settlement for 2007. TransCanada has also recently negotiated a five-year settlement for 2007 to 2011 that was approved by the Board in May 2007. TPTM negotiated another five-year deal with its shippers for the years 2006 to 2010. TQM is currently operating under interim tolls which are based on a five-year settlement which expired on 31 December 2006. TQM is in discussion with its shippers regarding tolls for 2007 and future years. Westcoast Transmission and its shippers are currently in the second year of a two-year settlement for 2006 and 2007.

These negotiated settlements have resulted in a reduction in the regulatory burden for parties, both in terms of the time spent in hearings and the associated costs. They have also contributed to a better alignment of interests between pipeline companies and their shippers.

FIGURE 22

Negotiated Settlements Timeline



Notes:
1 - In negotiations

Alliance and M&NP were not in service during these years

4.2 Pipeline Tolls Index

Stable and reasonable tolls are a key area of concern for users of the transportation and an indicator of the system's efficiency. The Board tracks year-to-year variations in tolls; the section below describes movements in the benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost of service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase.

Natural Gas Pipeline Tolls

Figure 23 shows indexes of benchmark tolls[4] for TransCanada's Mainline, Westcoast Transmission, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator[5] all normalized to the year 2006.[6]

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 and 2006 the toll fell, primarily due to increased contract demand: it remains below the level that it was in 2000.

Westcoast's tolls were relatively flat until 2004, when this toll increased by over 15 percent due to decontracting of firm services. Further reductions in volumes in 2006 caused a further 32 percent increase in 2006 tolls.

4 The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

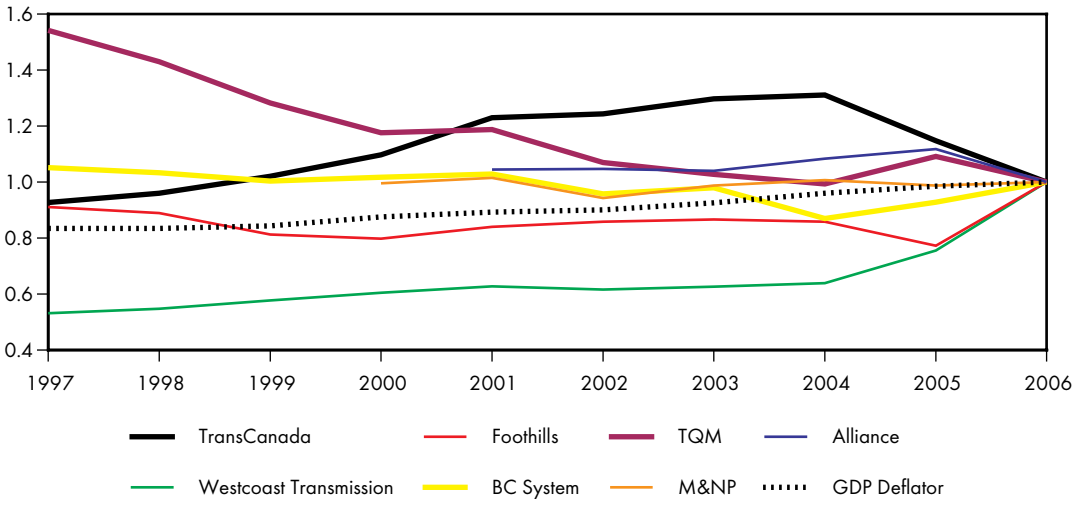
5 The implicit GDP deflator for 2006 is an estimate using actual data for the first half of the year and data estimated by Informetrica for the second half of the year.

6 Differing pipeline distances add to the challenges in comparing tolls between individual pipelines. Some normalization is required. Here the tolls are normalized only with respect to their own changes over time. The year of normalization is arbitrary; the most recent was selected as some tolls are only available for more recent years.

FIGURE 23

NEB-Regulated Natural Gas Pipeline Benchmark Tolls

Normalized to 2006 = 1.00



TQM's benchmark toll is below the 1997-1999 levels. This lower level is partly due to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system, but has increased in 2006 due to lower volumes and the end of the ten year period in 2005 for the deferred tax payback.

The B.C. System benchmark tolls in 2006 were close to the 1997 level. An (over 10 percent) increase in throughput volumes from 2003 reduced the 2004 benchmark toll on the B.C. System. M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

Oil Pipeline Tolls

Figure 24 presents indexed values for the benchmark tolls of Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2006.[7]

Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2003. The tolls increased the most in 2000, 2004 and 2006. Under its negotiated settlement, Enbridge was able in the following year to recapture the revenue shortfall attributable to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization with throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

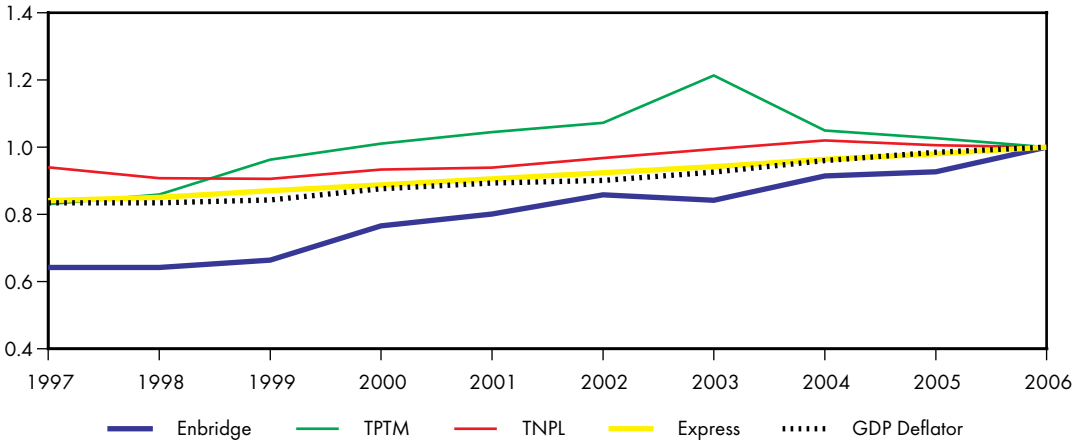
TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last three years. The large 1999 increase was due to throughput forecasts. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which lead to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped, primarily due to the disposition of deferrals for 2003 higher revenue. TNPI and Express's benchmark tolls moved roughly in line with the GDP deflator from 1997 to 2006.

7 The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

FIGURE 24

NEB-Regulated Oil Pipeline Benchmark Tolls

Normalized to 2006 = 1.00

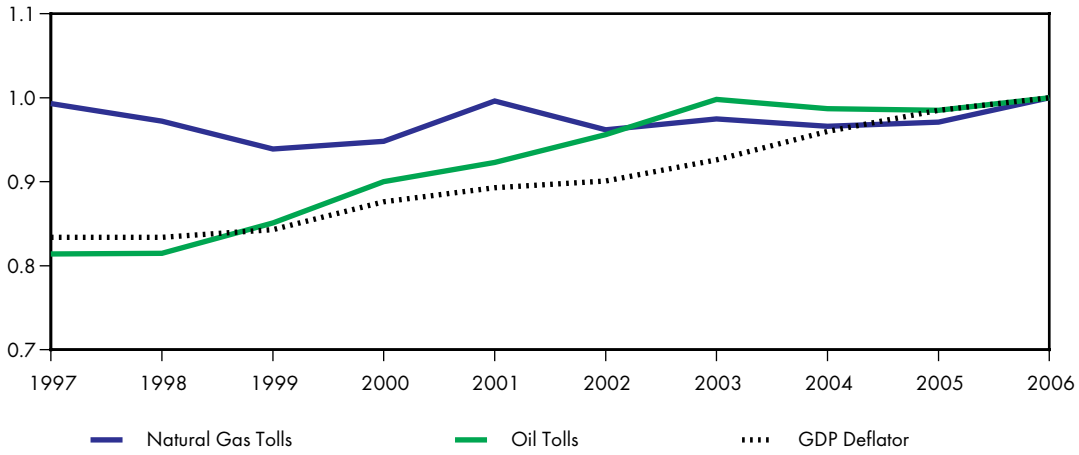


* Enbridge Toll does not include terminal and tankage fees.

FIGURE 25

Oil and Natural Gas Pipeline Benchmark Tolls

Normalized to 2006 = 1.00



Comparison of Gas and Oil Pipeline Tolls

Figure 25 presents the GDP deflator with simple averages of the gas and oil benchmark pipeline tolls indices (reported in Figures 23 and 24).[8] From 1997 to 2006, average natural gas pipeline tolls have been relatively flat despite the rise in the GDP deflator. Over the same period, oil pipeline tolls increased but the net increase over the period has matched the GDP deflator. Throughput volumes have been the primary driving factor in variations during the period.

8 No adjustments are made for the relative volume, capacity or length of the individual pipelines.

4.3 Shipper Satisfaction

4.3.1 NEB Pipeline Services Survey

The Board conducted its third annual Pipeline Services Survey in early 2007 to obtain direct feedback from the shippers of major NEB-regulated pipeline and midstream companies on the quality of service provided by those pipelines. The Board also used this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

To conduct this year's survey, the Board used a web-based survey tool, called Inquisite, which was sent to shippers directly via e-mail. For each survey received, shippers completed one response which reflects their company's corporate views on the services provided by the pipeline and midstream company being surveyed and on the services provided by the Board. The overall response rate for the survey was 27.0 percent, which was lower than last year's rate of 33.5 percent. The number of surveys sent out this year was 523, approximately 100 more than last year.

After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each company and its shippers with detailed company-specific results including the average rating and distribution of responses for each question as well as the verbatim comments received from shippers, with the names of the respondents excluded.

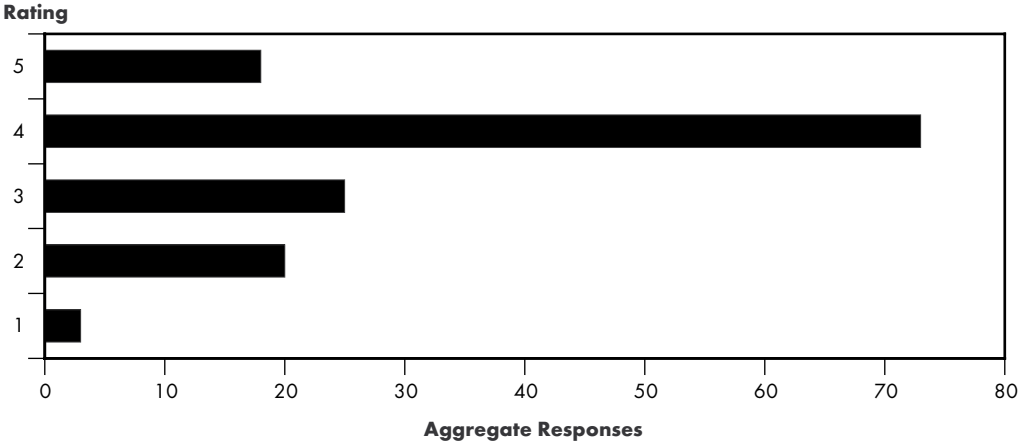
Appendix 3 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/Survey Results.

Pipeline Services

Figure 26 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline/midstream companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The industry average score of 3.60 was slightly higher than the score of 3.57 in last year's survey. Sixty-five percent (65%) of the respondents gave their company a rating of satisfied or very satisfied on overall quality

FIGURE 26

Shipper Satisfaction on Pipeline Quality of Service



of service, compared to 58 percent last year. Based on these results, the Board is able to conclude that shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.

The three areas where shippers indicate that pipeline and midstream companies are doing very well are:

- Timeliness and accuracy of invoices and statements;
- Physical reliability of pipeline operations; and
- Satisfaction with transactional systems.

The three areas where shippers believe that companies could improve the most are:

- Reducing the level of transportation tolls or midstream charges;
- Exhibiting an attitude of continuous improvement and innovation; and
- Ensuring that settlements or tariff arrangements work well.

Feedback on the Board

The 2007 survey indicated that approximately 59 percent of shippers are either satisfied or very satisfied with the Board's performance with creating an appropriate regulatory framework and 55 percent of shippers are either satisfied or very satisfied with the Board's processes to resolve disputes. Both of these results were lower than in the 2006 survey. Two areas for improvement noted by shippers were for the Board to build its internal capacity to serve Canadians better and to provide effective regulatory processes that are more accessible to stakeholders and yield more timely decisions. Both of these areas are addressed in the Board's 2007-2010 Strategic Plan, which can be found at www.neb-one.gc.ca/AboutUs/strtgcpln2007_2010_e.htm.

4.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a formal complaint to the Board. The complaint would then be dealt with through appropriate dispute resolution, a formal complaint process or, in some cases, the parties may be able to negotiate a solution to the concern. There was only one formal shipper complaint during the past year which involved the Board.

Several shippers on Cochin Pipe Lines Ltd. (Cochin)

In December 2006, Cochin filed for new rates to become effective 1 January 2007. The new rates reflected increases ranging from 91 to 580 percent across both Regular Volume Rates and Incentive Volume Rates and included a new toll segment from Detroit, Michigan to Windsor, Ontario. The Board received 11 letters from Cochin's shippers and interested parties indicating concern with the magnitude and timing of the rate increases. Shortly thereafter, Cochin initiated settlement discussions with its shippers and, in February 2007, filed a negotiated settlement and letters of support from many of its shippers. Following further negotiations with one opposing shipper, Cochin advised that it and the shipper had reached a resolution of the outstanding issue. Cochin's toll settlement was subsequently approved by the Board in May 2007.

4.3.3 *Service Enhancements*

On an ongoing basis pipelines may propose modifications to their services as circumstances and needs of their customers change or innovative ideas are brought forward. Normally, the pipeline and its shippers will discuss and agree upon proposed service enhancements in their tolls task force prior to submission to the Board and ultimate adoption. However, if the task force is unable to agree on the service, a party may still bring the issue directly to the Board.

Coral Energy Canada Inc. (Coral)

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its long haul contracts on the Mainline. In February 2006, The Board approved Coral's application which sought to extend FT-RAM credits to short-haul contracts held by the same shipper, which when combined with a long-haul contract forms a continuous long-haul on the TransCanada Mainline. The Board subsequently also approved amendments supported by an unopposed tolls task force resolution to extend the FT-RAM pilot project for an additional year.

TransCanada

In May 2006, TransCanada applied to the Board for approval of two new services on its Mainline, designed to meet the fluctuating demands of new gas-fired electric generation in Ontario. The Board has approved the implementation of these services; Firm Transportation - Short Notice (FT-SN) and Short Notice Balancing (SNB) and the proposed tolling method for FT-SN. However, the Board directed TransCanada to develop an alternate tolling method for SNB service.

Westcoast

After lengthy discussions with the Toll and Tariff Task Force on the possible decontracting on transmission facilities, Westcoast and its customers agreed to the following firm service enhancements, which were subsequently approved by the Board in RHW-1-2005 and implemented in 2006:

- Term differentiated rates (offering lower rates for longer term commitment) were taken up by about 25% of eligible volumes starting in January 2006.
- Authorized Over Run service which provides firm service customers with access to additional capacity at a higher priority than interruptible service was successfully utilized during a scheduling constraint in late 2006.
- Cross-corridor crediting was implemented on the various corridors on Westcoast's T-North system in 2006.

Moreover, to address periodic imbalance management issues, Westcoast, in collaboration with its shipper community, proposed a Supply Imbalance Management Strategy that was unanimously supported by its Toll and Tariff Task Force, and is expected to be implemented in 2007.

4.4 Chapter Summary

The following observations are made in this chapter:

- Shippers are able to resolve the majority of their tolling issues of interest with pipelines through the negotiated settlement process;

- Pipeline tolls have been relatively stable on average, although particular regional situations may cause greater variability in some areas;
- Based on responses to the NEB Pipeline Services survey; shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.
- There are few formal service complaints; and
- Development of pipeline service enhancement continues.

The Board concludes that pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). Shippers are also reasonably satisfied with the role played by the Board itself, with some suggestions incorporated into the Board's own planning.

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PIPELINE FINANCIAL INTEGRITY AND ABILITY TO ATTRACT CAPITAL

Pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors relevant to these areas, starting with the area over which the Board has the most direct influence.

5.1 Common Equity

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations.

Deemed Common Equity Ratios

The Board approves a deemed common equity ratio for the Group 1 pipeline companies that it regulates.[9] When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a return on equity (ROE) and deems a common equity ratio for the regulated entity. Alternatively, some Group 1 pipeline companies successfully negotiate a comprehensive tolls settlement with their shippers, which may include capital structure and return on equity. In this instance, the Board still considers the overall settlement. Given the extent of negotiated settlements, many of the equity ratios have been determined by negotiation among the parties involved. Through this mechanism, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

TABLE 6

Deemed Common Equity Ratios (Percent)

	2002	2006	2007
Alliance	30	30	30
Foothills	30	36	36
M&NP	25	25	29.27
TQM*	30	30	30
TransCanada B.C. System	30	36	36
TransCanada Mainline	33	36	40
Westcoast Transmission	30	35	36

* TQM's common equity ratio was specified in its negotiated settlement that expired on 31 December 2006.

Table 6 shows the deemed common equity ratio for some NEB Group 1 pipeline companies through adjudication or negotiation. TransCanada, Westcoast Transmission, B.C. System, and Foothills have increased their deemed common equity ratios between 2002 and 2006. The market considers these increases to be credit positive, lowering the financial risk of the pipeline companies.

9 A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

Return on Common Equity

Return on equity is commonly used to assess the operating profitability of a company. Financial markets define ROE as net income divided by common equity.

For NEB-regulated pipeline companies, ROE is the return on the equity portion of the rate base that is approved by the Board and is determined either through adjudication or negotiation. A higher ROE is typically preferred by investors.

Annually, the Board establishes an approved-ROE following the method outlined in RH-2-94. It is applicable to pipelines that the Board regulates, except those that have Board approved alternative rates. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentives, profit-sharing mechanisms and cost reductions.

Table 7 shows the achieved ROE for several NEB-regulated pipeline companies from 2002 to 2006 along with the ROE approved by the NEB in accordance with the RH-2-94 Formula[10]. As per their respective negotiated settlements, Enbridge, TPTM and Trans-Northern are not required to submit their Financial Surveillance Reports to the NEB, which would include achieved ROEs. Therefore, these pipeline companies are not included in Table 7. Other companies are included in Table 8, but are not subject to the RH-2-94 Formula ROE: Alliance and M&NP have negotiated ROEs with their shippers,[11] and Westcoast's Field Services Division is financially regulated on a complaint basis as described in the Framework for Light-handed Regulation (RHW-1-98). Fees for gathering and processing services are negotiated individually with shippers. TransCanada and TQM have negotiated settlements which use the RH-2-94 Formula as a basis and allow incentives causing some variations from the Formula rate.

The RH-2-94 Formula produced an ROE of 8.88 percent for 2006, falling each year since 2003 because of low interest rates. From 2002 to 2006, for pipeline companies subject to the RH-2-94

TABLE 7

Achieved ROEs and the RH-2-94 Formula ROE (Percent)

	2002	2003	2004	2005	2006
Transmission					
Alliance	11.25	11.25	11.25	11.25	11.25
Foothills	9.53	9.79	9.56	9.46	8.88
M&NP	12.95	12.31	13.75	14.31	14.68
TQM	9.80	10.21	9.84	9.92	8.99
TransCanada B.C. System	9.53	8.21	8.51	9.46	8.47
TransCanada Mainline	9.95	10.18	9.83	9.66	8.92
Westcoast Transmission*	13.44	12.93	10.28	10.82	9.16
NEB RH-2-94 Formula	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**
Midstream					
Westcoast Field Services*	14.87	6.76	11.63	12.48	10.46

Source: NEB Surveillance and Annual Reports

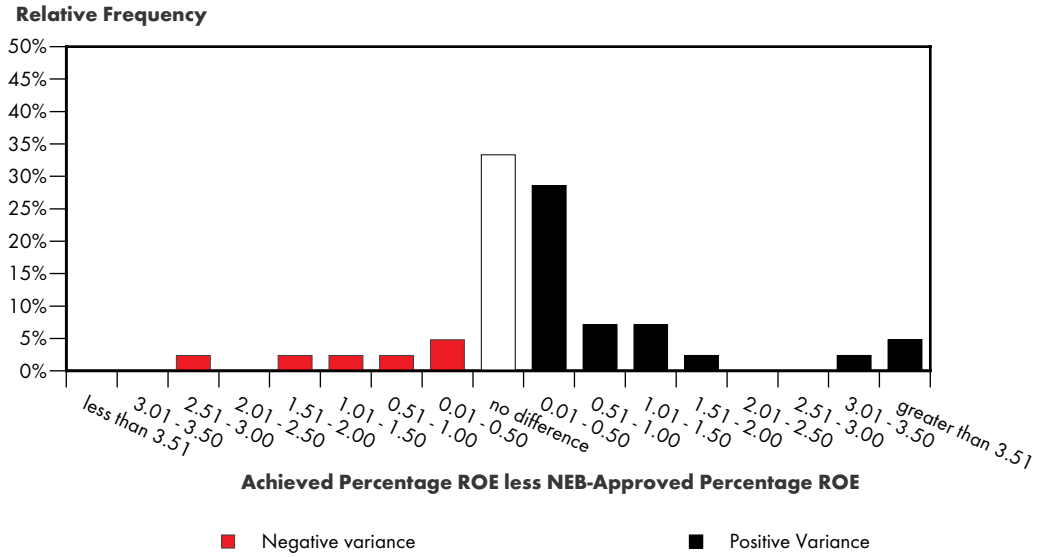
* excluding CWIP (construction work in progress) and, in the case of Transmission, deferrals.

10 The formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

11 The settlements were subsequently approved by the Board. Alliance's settlement sets its ROE at 11.25 percent over this period. M&NP has a base return on equity of 12 percent for 2007; up to and including 2006 their base rate was 13 percent, with incentive potential.

FIGURE 27

Variance from NEB-Approved ROE for the Years 2001 to 2006



Source: NEB Surveillance Quarterly and Annual Reports. Includes TransCanada Mainline and B.C. System, TQM, Westcoast Transmission system, and M&NP, as well as Foothills and Alliance which earn precisely their allowed ROE.

Formula ROE, only the TransCanada B.C. System has failed to earn an ROE at or above the Formula return in each year.

Most pipelines have, or have proposed, negotiated settlements. Three settlements have allowed ROEs that are different than the Formula ROE: Alliance, M&NP, and Trans-Northern. In the case of Alliance and M&NP, the ROE was fixed for an extended period. Other settlements use the RH-2-94 Formula as the allowed ROE and many of these settlements provide varying degrees of incentives to enable pipelines to earn more than the Formula ROE. As a result of the various incentives, most Group 1 pipelines have achieved actual ROEs that are greater than allowed ROEs. With the low interest rate environment, the RH-2-94 Formula produces an ROE of 8.46 percent for 2007.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for the TransCanada Mainline, the B.C. System, TQM, the Westcoast Transmission system, and M&NP. Also Foothills and Alliance are included; by their settlement their achieved ROEs equal their approved ROEs. From 2001 to 2006, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 86 percent of the time. The stability and predictability of returns is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet or outperform approved levels through cost reductions, incentives and profit sharing mechanisms.

5.2 Financial Ratios

Financial ratios, based on financial statement information, can be useful in describing a company's performance and financial integrity. A financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. A variety of ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Reported financial information often pertains to a parent company, and includes non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some ratios relating to the financial risk of certain companies with NEB-regulated pipelines.

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk attributed to the nature of a particular business activity and for pipelines typically includes supply, market, regulatory, competitive and operating risks. Financial risk increases as the proportion of debt increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of debt coverage gives some indication of the sustainability and value of the equity, and possible ability to pay dividends.

A company's financial risk can be described by ratios such as interest and fixed-charges coverage and cash flow-to-total debt and equivalents.

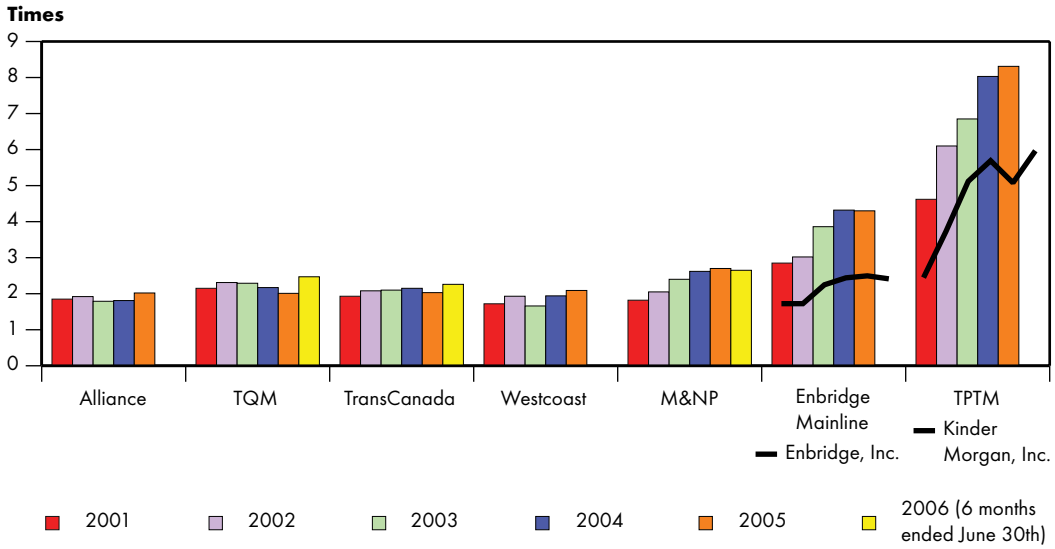
Interest and Fixed-Charges Coverage Ratios

An *interest coverage ratio* describes a company's ability to make interest payments and repay its debt obligations. It is defined as Earnings Before Interest and Taxes (EBIT) divided by interest charges. The metric presented below is similar: the *fixed-charges coverage ratio* describes the ability to make interest payments as well as other types of fixed payments a company is obligated to make. It is defined as earnings before interest, fixed charges and taxes divided by fixed-charges, including interest. Higher ratios indicate a higher likelihood that the company will be able to meet its obligations and, if all other things are equal, could indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 28. Complete data are not available consistently for all companies: the Enbridge Mainline is shown in the block data, the consolidated company Enbridge Inc. is shown as the line. TPTM information was not available on a stand-alone

FIGURE 28

Fixed-Charges Coverage Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2006.

basis for 2006: the overlay line shown is its new owner, Kinder Morgan Inc. The average fixed-charges coverage ratio for the companies for which data is available is 2.42, which is a 6 percent increase year-over-year for those companies.[12]

No company saw its 2006 fixed-charges coverage ratio lower than its 2001 levels. From 2001 to 30 June 2006, the fixed-charges coverage ratio for the five natural gas pipeline companies shown increased modestly from a little under 2 times to around 2.2 by 2006. The two oil pipelines (Enbridge (Mainline) and TPTM, in each case representing the oil pipelines business unit) had higher ratios, which increased more rapidly. TPTM's fixed-charges coverage ratio has been higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carried less debt, and had lower fixed payments. The continuing increases in fixed-charges coverage ratios for all companies is one metric signaling a decrease in the pipeline companies' financial risk, when considered as a group.

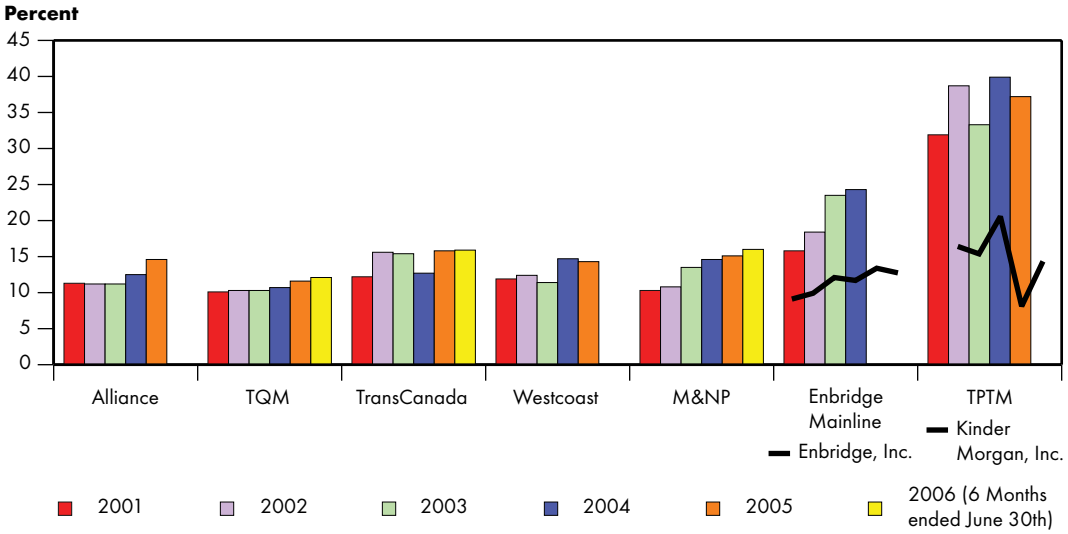
Cash Flow-to-Total Debt and Equivalents Ratio

The cash flow-to-total debt and equivalents ratio is another way of describing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and debt equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate that it has greater borrowing capacity.

The cash flow-to-total debt and equivalents ratio for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 29. As earlier noted, this ratio is not available for the pipeline units. The average cash flow-to-total debt and equivalents ratio for these companies was 14.2 percent for the partial year ending June 2006, a slight increase from the year before.[13] TPTM's cash

FIGURE 29

Cash Flow-to-Total Debt and Equivalents Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2005 and 2006.

12 This average includes only Alliance, M&NP, TransCanada and Enbridge Inc.; this group had a simple average of 2.28 in 2005 and 1.93 in 2001. In last year's report, the average of 3.22 cited included other pipelines, such as TPTM.

13 The ratio is heavily influenced by the availability of TPTM data. In the 2006 report, the average ratio was 17 percent including data available for TPTM. Without TPTM the ratio was much more modest. Using only the companies which have data available this year, the average is 14.2 for 2006, slightly up from 14.0 for 2005 and up notably from 10.0 in 2000.

flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by more than 20 percent from 2000 to 2006. The increase has been steady without any noteworthy periods of deterioration. The increase in this coverage ratio, and the consistent increase in cash flow-to-total debt and equivalents support the observation from the fixed-charges coverage that, on average, these pipeline companies' financial risk has been decreasing.

5.3 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies, Dominion Bond Rating Service (DBRS), Standard & Poor's (S&P), and Moody's. In general, credit ratings provide an assessment of the probability that a debt issuer will live up to its obligations and as such are an indication of the financial integrity of the rated company. Credit ratings assigned to a company generally reflect the consolidated operations of the entire company and not solely the regulated portion. Consequently, the credit rating for companies such as Enbridge, TransCanada and Westcoast that have both regulated and non-regulated operations may be influenced by its non-regulated operations. In addition, the credit ratings may be influenced to some extent by a parent company. Credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies. See Appendix 4 for a comparison of the rating scales for DBRS, S&P, and Moody's.

DBRS

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. The key credit considerations will vary industry by industry; however, some of the common factors that are considered for most ratings are: core profitability, asset quality, strategy and management strength, and the financial and business risk profile.

For pipelines, the following specific factors are also considered in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. The credit ratings for most Group 1 pipeline companies shown in Table 8

TABLE 8

DBRS Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Current
Alliance	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
Enbridge Pipelines	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)/Stb
Express[1]	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
M&NP	A	A	A	A	A	A/Stb
TQM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
TransCanada	A	A	A	A	A	A/Stb
Trans Mountain	A(low)	A(low)	A(low)	A(low)	repaid	repaid
Trans-Northern	NR	NR	NR	A(low)	A(low)	A(low)/Stb
Westcoast[2]	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb

1 Senior secured
2 Unsecured debentures
NR Not rated

indicates that the ratings have remained stable from 2002 to the present, varying from A(low) to A(high), and there have been no recent rating changes.

Standard & Poor's

An S&P credit rating reflects a borrower's capacity and willingness to meets its financial commitments on a timely basis. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and

economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

The rating histories for several Group 1 pipeline companies are provided in Table 9. The table illustrates that the ratings have remained stable from 2002 to the present, varying from 'BBB+' to 'A-'. There have been two recent rating changes. First, the credit rating on the long-term debt of Westcoast Energy Inc. was upgraded to 'BBB+' in January 2007 from 'BBB', which had been in place since February 2004. The rating change was based on the ownership change at the parent company level that occurred effective 2 January 2007 when Duke Energy Corporation completed the spin-off of its natural gas business (including Westcoast) to Spectra Energy Corporation, a new publicly traded company. Second, in April 2007, S&P revised its outlook on TranCanada from 'negative' to 'stable'. The negative outlook on TransCanada's credit rating had been in place since December 2002, and was initially associated with TransCanada's acquisition of a significant interest Bruce Power in February 2002. S&P noted that TransCanada's recent acquisition of ANR and its investment in the Keystone oil pipeline project provide a stabilizing offset to the declining rate base and lower return on equity from its traditional business.

Both DBRS and S&P have expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by these credit rating companies indicate that NEB-regulated companies are all rated investment grade.

TABLEAU 9

S&P Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Cote actuelle
Pipelines Enbridge	A-/Neg	A-/Stb	A-/Stb	A-/Stb	A-/Stb	A-/Stb
M&NP[1]	A/Stb	A/Stb	A/Stb	A/Stb	A/Stb	A/Stb
TQM	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb
TransCanada	A-/Watch/Neg	A-/Watch/Neg	A-/Watch/Neg	A-/Neg	A-/Neg	A-/Stb
Trans Mountain	BBB+/Neg	BBB/Stb	BBB/Stb	BBB/Stb	debt repaid	debt repaid
Westcoast[2]	A/Stb	BBB+/Stb	BBB+/Stb	BBB/Watch/Neg	BBB/Stb	BBB+/Stb

1 Senior secured
2 Unsecured debentures

Moody's

Moody's credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic considerations:

- The risk to the debt holder of not receiving timely payment of principal and interest on the specific debt security.
- A comparison of the level of risk with that of all other debt securities.

Like S&P, Moody's focuses its ratings on the overall creditworthiness of the consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future, thus its primary focus is on the predictability of future cash generation. This determination is built on an analysis of the individual issuer and of its strengths and weaknesses compared to those of its peers worldwide. An examination of factors external to the issuer is also conducted, including industry- or country-level trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several Group 1 pipeline companies are provided in Table 10. All of Moody's ratings placed the pipelines in the investment grade category, specifically rated 'medium grade' to 'upper-medium grade'.

There has been one recent rating change by Moody's. In March 2007 Moody's downgraded the ratings on the senior unsecured debt of Enbridge Inc. one notch to Baa1 from A3.[14] Moody's stated that the one notch downgrade was based on concerns relating to the company's weak financial profile, the complexity of its organizational and capital structure, and the scope and financial impact of the company's substantial organic growth plans.

5.4 Comments by the Investment Community

Access to capital market is necessary for pipeline companies to maintain and, potentially, expand their systems as the needs of the transportation market changes. Board staff met with credit rating analysts, equity analysts, and suppliers of capital such as insurance and pension funds to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets as well as their views on transportation markets and the current regulatory environment in Canada.

TABLE 10

Moody's Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Current
Alliance[1]	A3	A3	A3	A3	A3	A3
Embridge Inc.	A2	A3	A3	A3	A3	Baa1
Express[2]	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
M&NP[2]	A1	A1	A1	A2	A2	A2
TransCanada[1]	A2	A2	A2	A2	A2	A2

1 Unsecured debentures
2 Senior secured

14 Enbridge Inc. is the parent company of Enbridge Pipelines Inc., which owns the Enbridge Mainline. Unlike DBRS and S&P, Moody's does not rate the debt issued by Enbridge Pipelines Inc.

There was a consensus among parties that there is substantial liquidity in both domestic and export global capital markets. Solid economic growth in recent years, low interest rates, the accumulation of capital in pension funds and the ability of private equity funds to borrow large sums at low rates from finance companies were among the reasons cited for the current situation, which was characterized as 'a lot of money chasing too few assets'. Regulated businesses, along with infrastructure and real estate, were seen as particularly attractive investments. It was noted that the federal tax changes made in October 2006 with respect to income trusts and increases in the dividend tax credit also increased demand for shares of dividend paying companies like financials, utilities and pipelines, at least temporarily.

Given this environment, there was agreement that NEB-regulated pipelines have not had difficulty accessing equity or debt markets. The parent companies of TransCanada PipeLines Limited and Enbridge Pipelines Inc. recently went to the equity market and collectively raised more than $2 billion. Both companies have also had substantial debt issues recently. However, some parties expressed concern that on a stand-alone basis the regulated entities themselves might have difficulty attracting capital given low ROEs. Others felt that the regulated entities would be able to attract capital but that the terms under which they did so may be more costly than for the consolidated entity.

Again this year the investment community noted that price-to-earnings ratios of utilities in Canada have been higher than those in the U.S. because of large energy infrastructure investment opportunities, a more stable regulatory environment and global interest in Canadian stocks. While there is currently substantial liquidity, it was noted that capital markets could change and this could happen very quickly and result in considerable volatility.

Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

5.5 Chapter Summary

The observations made in this chapter may be summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2001;
- Deemed common equity ratios have increased since 2001;
- Achieved ROEs have in most cases been greater than or equal to their NEB-approved levels since 2001;
- Approved ROEs have been predictable, but declining and may now be too low;
- Credit ratings continue to be investment grade; and
- The investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity, but noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

In general, these observations signal that, currently pipelines companies have adequate financial strength to attract capital on reasonable terms and conditions.

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CONCLUSIONS

Based on the criteria identified in the Introduction to this report, the Board believes that the Canadian hydrocarbon transportation system continues to work effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The price differentials and capacity utilization charts indicate that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. The existence of some excess capacity out of the WCSB has provided suppliers with the flexibility to access markets of their choice at most times. Proposed pipeline projects are mainly directed towards providing connection to new supplies or addressing bottlenecks in the market area.

   Capacity remains very tight on oil pipeline systems. While the capacity utilization indicators show that there was spare capacity on some of the pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. It is likely that export crude oil pipelines out of Western Canada may experience periods of apportionment by the fourth quarter 2007, and this may continue for the next 18 months. As indicated by Figure 21, no significant pipeline capacity is expected to be added between now and 2009. The industry and the pipeline companies are working together to develop a number of initiatives to reduce and/or eliminate the impacts of apportionment.

   The number of announced and proposed pipeline and expansions, and the transfer of under-utilized gas pipeline facilities on the TransCanada Mainline to transportation of crude oil, illustrates that the hydrocarbon transportation systems are responding and have the ability to make adjustments to pipeline capacity as market conditions change.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipelines.** Once again, shippers rate the physical reliability of pipeline operations highly and express the most concern around the level of pipeline tolls.

3. **NEB-regulated pipeline companies are financially sound and have been able to attract capital on reasonable terms and conditions.** While it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies, the investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity. However, the investment community also noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

As identified in Chapter 3, there are a significant number of pipelines proposed to ensure that the Canadian transportation system has sufficient capacity to deliver the additional volumes of oil and natural gas to serve new and growing markets. The challenge for the pipeline transportation industry is to put appropriate capacity in service corresponding with changes in production and market requirements. For this to happen there must be adequate and predictable lead times to achieve

sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct facilities.

A key component and ongoing challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve ongoing efforts to coordinate regulatory activities with other jurisdictions and to provide clear regulatory processes with predictable timelines. New investment can be frustrated when unexpected regulatory hurdles create delays or unpredictable timelines which may introduce uncertainty from changing supply and market conditions and business risk. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained. Given the large capital outlay and the long-term nature of these investments, market participants seek to ensure that the optimal decisions are made.

The Board recognizes that this report represents only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

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STAKEHOLDER CONSULTATION

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
Canadian Gas Association
Canaccord Adams
Caisse de dépôt et placement du Québec
CIBC World Markets
Cochin Pipe Lines Ltd.
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
Foothills Pipe Lines Ltd.
Industrial Gas Users Association
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Investor Services
Ontario Teachers' Pension Plan
RBC Capital Markets
Scotia Capital
Standard & Poor's
Sun Life Financial
Terasen Pipelines Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc.

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GROUP 1 AND GROUP 2 PIPELINES

Regulated by the NEB As of 31 December 2006

Group 1 Gas Pipelines

Alliance Pipeline Ltd.
Foothills Pipe Lines Ltd.
Gazoduc Trans Québec & Maritimes Inc.
Maritimes & Northeast Pipeline Management Ltd.
TransCanada PipeLines Limited
TransCanada PipeLines Limited, B.C. System
Westcoast Energy Inc.

Group 1 Oil and Products Pipelines

Cochin Pipe Lines Ltd.
Enbridge Pipelines Inc.
Enbridge Pipelines (NW) Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipelines Inc.

Group 2 Natural Gas and Natural Gas Liquids Pipelines

AltaGas Pipeline Partnership
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Burlington Resources Canada (Hunter) Ltd.
Canada Customs and Revenue Agency
Canadian Natural Resources Limited
Canadian-Montana Pipe Line Corporation
Centra Transmission Holdings Inc.
Champion Pipeline Corporation Limited
Chief Mountain Gas Co-op Ltd.
DEFS Canada L.P.
Delphi Energy Corporation
Devon Canada Corporation
Devon Energy Canada Corporation

DR Four Beat Energy Corp.
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
Enermark Inc.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.
Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
Kaiser Exploration Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Marauder Resources West Coast Inc.
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
NuVista Energy Ltd.
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Shiha Energy Transmission Ltd.
Suncor Energy Inc.
Sword Energy Limited
Talisman Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vault Energy Inc.
Vector Pipeline Limited Partnership
County of Vermillion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

Group 2 Oil and Products Pipelines

Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited
ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd. (as agent and general partner of the Pembina North Limited Partnership)
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.

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PIPELINE SERVICES SURVEY

Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates "Very dissatisfied" and 5 indicates "Very satisfied". See the Board's website for the complete details

1. How satisfied are you with the physical reliability of the pipeline company's operations?

1	2	3	4	5	Average
4	18	12	74	31	3.79

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc)?

1	2	3	4	5	Average
0	24	16	75	22	3.69

3. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

1	2	3	4	5	Average
7	7	14	75	31	3.87

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc) provided by the pipeline company?

1	2	3	4	5	Average
3	17	21	79	19	3.68

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

1	2	3	4	5	Average
7	13	34	70	15	3.53

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
10	30	36	51	11	3.17

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
9	22	32	54	21	3.41

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	20	37	54	19	3.44

9. How satisfied are you with the suite of services offered by the pipeline company?

1	2	3	4	5	Average
4	13	40	67	10	3.49

10. How satisfied are you with the level of this pipeline company's tolls in relation to the transportation services your company receives?

1	2	3	4	5	Average
7	26	42	53	4	3.16

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
11	16	38	45	14	3.28

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
11	8	47	52	5	3.26

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
3	20	25	73	18	3.60

14. On an overall basis, has the pipeline company's quality of service in the last year:

Improved	18	13%
Remained the Same	100	72%
Decreased	20	15%
Total	**138**	**100%**

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
4	10	39	67	9	3.52

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
4	6	39	53	7	3.49

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

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DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by Dominion Bond Rating Service (DBRS), Standard and Poor's (S&P), and Moody's when rating long-term debt.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

Credit Quality	DBRS	S&P	Moody's
Investment Grade			
Superior / High grade	AAA	AAA	Aaa
	AA (high)	AA+	Aa1
	AA	AA	Aa2
	AA (low)	AA-	Aa3
Good / Upper Medium	A (high)	A+	A1
	A	A	A2
	A (low)	A-	A3
Adequate / Medium	BBB (high)	BBB+	Baa1
	BBB	BBB	Baa2
	BBB (low)	BBB-	Baa3
Non-Investment Grade			
Speculative	BB (high)	BB+	Ba1
	BB	BB	Ba2
	BB (low)	BB-	Ba3
Highly Speculative	B (high)	B+	B1
	B	B	B2
	B (low)	B-	B3
Very Highly Speculative	CCC	CCC	Caa1
	CC	CC	Caa2
	C	C	Caa3
	D	D	Ca
			C

Note: DBRS and S&P ratings in the CCC category and lower also have subcategories "high/+" and "low/-" and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category.

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GOAL 3

Canadians benefit from efficient energy infrastructure and markets.

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BMO Capital Markets

Pipelines/
Gas & Electric Utilities

Industry Rating Pipelines: **Market Perform**

Industry Rating Gas & Electric Utilities: **Market Perform**

December 7, 2006
Toronto, Ontario

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2007 ROEs Decline to Unprecedented Levels; Ontario Gets Reprieve

Highlights

- The ugly got uglier – actual 2007 allowed ROEs declined by an average of 0.37% versus the average allowed return on equity for 2006. The average actual allowed return on equity in 2007 is 8.65% versus 9.01% in 2006.
- The announced allowed returns are fully reflected in our diluted EPS estimates over the 2007 and 2008 forecast period.
- Although we believe that the allowed returns established by the automatic adjustment mechanisms set out herein likely violate the Fair Return Standard and are confiscatory, they are in line with expectations and therefore neutral to our outlook.
- Companies with material exposure to these automatic adjustment mechanisms include Canadian Utilities Limited, Pacific Northern Gas, Gaz Metro L.P., Fortis Inc. and TransCanada Corporation. Companies with limited exposure to ROE adjustment mechanisms include: Enbridge Inc., Duke Energy, and TransAlta Corporation.
- There are a number of companies in our coverage universe with no exposure to these automatic adjustment mechanisms: Caribbean Utilities, and Emera Inc. The pipeline and power trusts/limited partnerships in our coverage universe generally do not have a material exposure to these mechanisms.
- On November 23, the Ontario Energy Board abandoned its generic licence amendment proceeding, the purpose of which, among other things, was to codify its approach to determining the allowed return on equity. The Board has also rejected the implementation of an alternative approach to determine the allowed return on equity for Ontario's local electricity distribution utilities. We believe that this alternative approach was seriously flawed and had no basis in reality.
- We rate the units of Fort Chicago Energy Partners, LP, Inter Pipeline Fund, and Northland Power Income Fund Outperform. We also rate the shares of Pacific Northern Gas Ltd., and Caribbean Utilities Co. Ltd. Outperform.
- We remain restricted on the units of Calpine Power Income Fund.

This report was prepared by an Analyst employed by a Canadian affiliate, BMO Nesbitt Burns Inc., and who is not registered/qualified as a research analyst under NYSE/NASD rules. For disclosure statements, including the Analyst's Certification, please refer to pages 10 to 12.

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The allowed rates of return on equity (ROE) for many of the pipeline and energy utility companies in our coverage universe are established by an automatic adjustment mechanism in the fall of each year and are highly dependent on forecast interest rates for the prospective fiscal period. As discussed below, the 2007 allowed ROEs for various jurisdictions have now been established and allowed ROEs, on a cumulative basis, have reached unprecedented lows.

A. The Calculations

Table 1 sets out the key variables that drive each of the automatic adjustment mechanisms, by regulator.

***Table 1**: Key Input Assumptions*

Regulator	Year Formula Effective	Month of Consensus Economics	Base GOC Yield	Equity Risk Premium	Adjustment Factor	2004A ROE	2005A ROE	2006A ROE	2007E ROE	Change 2007 vs. 2006
National Energy Board	1995	November	9.25%	3.00%	75%	9.56%	9.46%	8.88%	8.46%	-0.42%
British Columbia Utilities Commission - Terasen Gas (BCGU)	2006	November	5.25%	3.90%	75%	9.15%	9.03%	8.80%	8.37%	-0.43%
British Columbia Utilities Commission - Terasen Gas (Centra)	2006	November	5.25%	4.60%	75%	9.65%	9.53%	9.50%	9.07%	-0.43%
British Columbia Utilities Commission - PNG West Division/Tumbler Ridge	2006	November	5.25%	4.55%	75%	9.80%	9.68%	9.45%	9.02%	-0.43%
British Columbia Utilities Commission - PNG Ft. St. John/Dawson Creek/FortisBC	2006	November	5.25%	4.30%	75%	9.55%	9.43%	9.20%	8.77%	-0.43%
Alberta Energy and Utilities Board	2005	November	5.68%	3.92%	75%	9.60%	9.50%	8.93%	8.51%	-0.42%
Ontario Energy Board - Enbridge Gas Distribution	1998	October	7.25%	3.40%	75%	9.69%	9.57%	8.74%	8.39%	-0.35%
Ontario Energy Board - Union Gas[1]	1998	October	7.25%	3.55%	75%	9.62%	9.63%	8.92%	8.53%	-0.39%
Regie de l'energie[2]	1999	August	5.76%	3.84%	75%	9.45%	9.69%	8.95%	8.73%	-0.22%
Nova Scotia Utilities and Review Board				Formula Not Presently In Use						
Island Regulatory and Appeals Commission										
Newfoundland and Labrador Board of Commissioners of Public Utilities[3]	2000	Oct/Nov	5.60%	4.15%	80%	9.75%	9.24%	8.77%	8.60%	-0.17%

Notes:
(1) Issue of Consensus Economics used to calculate allowed ROE has varied.
October stipulated in June 29, 2006 Reasons for Decision re: 2007 Rates.
(2) Excludes 0.57% of Allowed Incentive Return in 2003, 1.51% in 2004, 1.95% in 2005, 0.38% in 2006, and approximately 0.75% in 2007
(3) Return on Equity for Newfoundland Power Inc. Fixed for two-years at 9.75% in decision dated June 20, 2003. Total Return Calculation methodology.
Source: BMO Capital Markets

As set out in Table 1, the allowed ROEs established for the 2007 period are an average of 0.37% lower than in 2006. The primary reason for the decline in allowed return is the precipitous drop in the implied forecast 30-year bond yield arising from: (i) reduction in the underlying Consensus Estimate for 2007 versus 2006 to 4.15% from 4.55%; and (ii) decline in the observed spreads between the 10-year and 30-year government of Canada bond yields, as published in the National Post throughout October of 2006 versus a similar period in 2005, to approximately 7 basis points from approximately 23 basis points.

Tables 2, 3, and 4 highlight the calculation of the allowed 2007 actual ROE for the National Energy Board (NEB), Alberta Energy and Utility Board (AEUB), and the British Columbia Utilities Commission (BCUC). Table 5 highlights our estimate of the allowed return on equity for Enbridge Gas Distribution, as per the automatic adjustment mechanism notionally used by the Ontario Energy Board (OEB). We note that that the OEB, unlike its utility peer group, does not publish or release the calculation for the allowed return for the utilities subject to its purview. We note that the formulas appear to vary between Union Gas and Enbridge Gas Distribution and also between the electricity and natural gas sectors.

***Table 2**: Calculation of the 2007 Actual ROE – Multi-Pipeline Cost of Capital*

Description		
2006 Calculated Return on Equity		8.88%
2006 Forecast Yield		4.78%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 3 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs[1]		0.07%
Forecast Long-Term (30-year) GOC Bond Yield - 2007		4.22%
	2007 Forecast Yield	4.22%
	Less: 2006 Forecast Yield	4.78%
	Difference	-0.56%
	Times 75% Adjustment Factor	-0.42%
	Plus: 2006 Approved Return on Equity	8.88%
	Equals 2007E Approved Return on Equity	8.46%

Note:
(1) Calculated by using the 10-year and 30-year Government of Canada bond yields published daily in the National Post throughout October of the current year
Source: BMO Capital Markets

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***Table 3**: Calculation of the 2007 Actual ROE – AEUB*

Description		
Calculated Return on Equity Per Decision		9.60%
Forecast Yield Per Decision		5.68%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 3 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs[2]		0.07%
Forecast Long-Term (30-year) GOC Bond Yield - 2007		4.22%
	2007 Forecast Yield	4.22%
	Less: 2006 Forecast Yield	5.68%
	Difference	-1.46%
	Times 75% Adjustment Factor	-1.10%
	Plus: Approved Return on Equity	9.60%
	Equals 2007E Approved Return on Equity	8.51%

Note:
(2) Calculated by using the 10-year and 30-year Government of Canada bond yields published daily in the National Post throughout October of the current year
Source: BMO Capital Markets

***Table 4**: Calculation of the 2007 Actual ROE – BCUC*

Description		
2006 Calculated Return on Equity		8.80%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 3 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs		0.07%
Forecast Long-Term (30-year) GOC Bond Yield - 2007		4.22%
	Benchmark Return per G-14-06	9.145%
	Long-Term (30-year)GOC Bond Yield Decision	5.25%
	2007 Forecast Yield	4.22%
	Less: Bond Yield from Decision	5.25%
	Difference	-1.03%
	Times 75% Adjustment Factor	-0.77%
	Plus: Approved Return on Equity Decision	9.145%
	Equals 2007E Approved Return on Equity	8.37%

Source: BMO Capital Markets

***Table 5**: Calculation of the 2007E ROE for Enbridge Gas Distribution – OEB*

Description		
2006 Calculated Return on Equity		8.74%
2006 Forecast Yield		4.70%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 12 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs		0.08%
Forecast Long-Term (30-year) GOC Bond Yield - 2006		4.23%
	2007 Forecast Yield	4.23%
	Less: 2006 Forecast Yield	4.70%
	Difference	-0.47%
	Times 75% Adjustment Factor	-0.35%
	Plus: 2006 Approved Return on Equity	8.74%
	Equals 2007E Approved Return on Equity	8.39%

Source: BMO Capital Markets

B. Allowed Returns are Confiscatory

We believe on a collective basis, that the allowed returns as established by the formulas highlighted above are confiscatory and likely violate the Fair Return Standard. This standard, as established by Canada's Supreme Court and accepted by the National Energy Board in 1971, states that a fair or reasonable rate of return should:

1. be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable earnings standard);
2. enable the financial integrity of the regulated enterprise to be maintained and permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the financial integrity and capital attraction standards); and
3. achieve fairness from the viewpoint of the customers and from the viewpoint of present and prospective investors (appropriate balance of customer and investor interests).

We believe that regulators have consistently refused to give weight to a number of arguments that would result in higher allowed returns, solely on the basis that to do so would result in higher customer rates.

- The North American capital markets are increasingly integrated and investors have the ability to invest in utility assets north and south of the border.
- There is merit incorporating U.S. market metrics into the analysis and that the Canadian benchmark equity portfolio (the S&P/TSX) may not meet the theoretical requirement for a diversified market portfolio.
- The returns on comparable investments with similar risk, whether they be Canadian or U.S. examples, should be considered.
- The allowed return on equity and deemed equity must satisfy all aspects of the Fair Return Standard and that no part of the Standard has priority.

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- The continued reliance on a derived 30-year government of Canada bond yield may not be a relevant proxy for the cost of debt (and/or a proxy for the risk free rate) for two key reasons: (i) the observed and anticipated reduction in the supply of government of Canada securities and the continued conversation in the financial market that the government may cease to issue debt securities at the long end of the curve may result in distortions in the market cost of these securities and thus the observed yields; and (ii) that corporate debt issuers do not have access to the debt capital market at government yield levels.

- No pipeline or energy utility in our regulated coverage universe has issued equity in the last five years to fund, on an unlevered basis, a dollar-for-dollar equity investment in utility rate base. Continued assertions by regulators that utilities have adequate access to capital are not credible with respect to the equity component, as access to equity has not been tested over the ensuing period. For example, On September 16, 2003, Fortis Inc. announced that it planned to acquire the assets of Aquila British Columbia and Aquila Alberta for $1.36 billion, including assumed debt. The company financed the transaction by assuming approximately $689 million of utility debt and issued approximately $170 million of holdco debt, $200 million of holdco preferred shares and new equity of approximately $350 million. Despite the levered nature of the transaction and the prospect for above average rate base growth at the two target utilities, the common shares of Fortis Inc. declined by 5% at the time the transaction was announced and the transaction was initially widely expected to be dilutive until 2006.

- None of the pipeline projects highlighted in our May 24, 2006, report entitled "Exchanging Fire", save and except the Canadian portion of the Southern Access Pipeline (with an approximate cost of $160 million versus an estimated cost to Enbridge of projects currently permitted and/or under way of $8 billion), are expected to earn the National Energy Board multi-pipeline decision return on equity. We note that in many instances, the market-based tolling arrangements with shippers result in a risk profile similar to that of the benchmark pipeline, the TransCanada Mainline pipeline.

- Continued investment in utility rate base by the owners of utilities is not an acquiescence that the allowed return on equity is appropriate and that investment may relate to other obligations including the utility's obligation to be the supplier or supply or last resort and fulfil the obligation to serve, maintain the safe and reliable operation of the utility, and may be fulfilling specific conditions of its operating licence.

- A failure by utility companies to annually litigate the allowed return on equity "formula" does not constitute acceptance of the adequacy of the allowed return. Rather, we believe that the lack of annual litigation reflects the cost of the process, the time required to pursue litigation that detracts from management's ability to focus on the efficient operation of the business and the potential damage to important utility regulatory and customer relationships.

- The evidenciary standard is too high and almost impossible to meet. Moreover, we believe that notwithstanding decisions from the Supreme Court that stipulate otherwise, utility regulators continue to rely heavily on their quasi-judicial and expert status to impose a bare-bones return on equity and drive down the deemed capital structure of

the utility in order to protect customers from prices, without the fear of reconsideration upon appeal. Regulators must establish the cost of equity and deemed equity not because they are experts in this regard, but in order to establish just and reasonable rates. The regulator is not permitted to consider the effects on customers in the determination of the allowed ROE and capital structure, and we do not believe that the regulator is permitted to factor in other policy objectives into its determination of the allowed return on equity; i.e., we do not believe that the regulator is permitted to reduce the allowed return on equity and/or deemed equity for small utility companies in order to encourage consolidation or any other specific policy objective. We believe in these situations, that the inclusion of these other factors in the assessment of cost of equity and designation of deemed equity, unlawfully transfers value to utility ratepayers from its legitimate owner, the utility shareholders.

C. Ontario Gets a Reprieve

On November 23, the Ontario Energy Board (OEB) issued a notice to participants regarding its Multi-year Electricity Distribution Rate Setting Plan, including the Cost of Capital, 2nd Generation Incentive Regulation Mechanism and Generic Licence Amendment Proceeding. The Board indicated that, pursuant to Staff and Panel recommendations, the Board discontinue its code-based approach (November 17 and November 20, 2006 respectively); that in the interests of achieving a more timely setting of electricity distribution rates for the 2007 rate year, the Board will instead implement its cost of capital and 2nd generation incentive regulation policies by means of guidelines. As a result, the Board discontinued the generic licence amendment proceeding, which was commenced on the Board's own motion.

On November 30, the Board issued a Draft Report on the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors and Associated Guidelines. The draft report details the Board's policies on cost of capital and 2nd generation incentive regulation, and draws on the work of Board staff and the input of interest parties since this consultation was initiated in April 2006. Also included are guidelines to assist parties in understanding how the policies will be implemented and information for distributors in preparing their rate applications for the 2007 rate year.

The Draft Report contains the following highlights with respect to the cost of equity capital and deemed capital structure:

- The Board has determined that the current approach to setting ROE will be maintained. The ROE will be determined based on the Long Canada Bond Forecast rate plus an equity risk premium. The Board's current approach has been in place for six years. The consultation process undertaken by the Board included a review of one method that would have required more time and greater costs for its implementation. We also note that the range of ROE produced by this alternative method was unacceptably low; well below the various rates of return discussed previously. The Board concluded that none of the approaches reviewed is better than the Board's current method.
- The Board's method will continue to include an implicit premium of 50 basis points (0.5%) for floatation and transaction costs.

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- The current method was established in 1999 as part of a review of cost of capital. The ROE calculated at that time is the starting point for the calculation and is 9.35% (as per Hydro One Network Inc.'s RP-1998-0001 Decision). This formula is ROE_t = 9.35% + 0.75 ($LCBF_t$ – 5.50%). The Long Canada Bond Forecast will use the average of the January consensus forecast of the 10-year Government of Canada bond yield 3 months ahead and 12 months ahead plus the difference between the observed yields on the 30-year Government of Canada bond yield and the 10-year Government of Canada bond yield as published by the Bank of Canada during the month of January (2007).
- No incentive returns for capital investments are appropriate at this time.
- No earnings sharing mechanisms are appropriate for second generation incentive rate making.
- The Board will include an adjustment to rates in 2008, 2009 and 2010 to transition distributors from their existing capital structures to a single deemed capital structure of 40% equity and 60% debt:
  - o For distributors starting at equity of 35%, the equity component will move in equal increments over two years until it reaches 40%.
  - o For distributors starting at equity of 45%, the equity component will move in equal increments over two years until it reaches 40%; and
  - o For distributors starting at equity of 50%, the equity component will move in equal increments over three years until it reaches 40%.

We believe that the following points are relevant about the draft guidelines:

- The current formula is not expected to result in a return on equity that is materially higher than the formulas previously discussed. We reiterate that the existing formulas result in an allowed return on equity that likely violates the Fair Return Standard and we believe them to be confiscatory.
- We are not convinced that a "one-size fits all" capital structure is appropriate and we are concerned that the Board's policy objectives of regulatory efficiency and LDC consolidation are driving force behind the single deemed capital structure approach. This may not be appropriate.
- We are not disappointed by the Board's decision to abandon the Licence Amendment proceeding and the rejection of the alternative approach to determining the return on equity. This latter item was seriously flawed and had no basis in reality. We set out our views on this approach in comments/reports dated June 27, August 8 and September 7, 2006.

D. Comparable Equity Securities

Canadian Gas Utilities

Company	TSX Ticker	Price (C$) 5-Dec-06	Shares O/S (mm)	Market Cap. (mm)	Earnings per Share 2004A	2005A	2006E	2007E	P/E Ratios 2004A	2005A	2006E	2007E	Dividend Rate	Yield	12-Month Target	Total Return	Rating
Duke Energy Corp.[2]	DUK[5]	$32.69	1089.6	$35,618	$1.32	$1.73	$1.78	$1.95	16.8	16.1	18.3	16.8	$1.28	3.9%	$32.00	1.8%	Market Perform
Enbridge Inc.	ENB	40.55	339.7	13,775	1.56	1.56	1.76	1.81	16.7	21.8	23.0	22.4	1.20	3.0%	40.00	1.6%	Market Perform
Enbridge Income Fund	ENF.UN	12.00	34.6	416	0.30	0.44	0.54	0.55	40.4	30.8	22.2	21.8	0.96	8.0%	11.50	3.8%	Market Perform
Fort Chicago Energy Partners L.P.	FCE.UN	10.75	133.7	1,437	0.74	0.59	0.64	0.47	14.1	20.9	16.8	22.9	0.93	8.7%	11.00	11.0%	Outperform
Gaz Métro[4]	GZM.UN	15.80	117.5	1,857	1.40	1.30	1.25	1.25	15.4	16.7	12.6	12.7	1.24	7.8%	16.50	12.3%	Market Perform
Inter Pipeline Fund	IPL.UN	8.39	199.5	1,674	0.46	0.48	0.67	0.48	17.6	20.1	12.5	17.5	0.84	10.0%	8.50	11.3%	Outperform
Pacific Northern Gas Ltd.	PNG	18.50	3.6	67	1.38	1.72	1.04	1.52	14.3	11.4	17.8	12.2	0.80	4.3%	20.00	12.4%	Outperform
Pembina Pipeline Income Fund	PIF.UN	15.60	121.9	1,902	0.53	0.65	0.81	0.84	23.5	22.0	19.3	18.6	1.32	8.4%	15.00	4.6%	Market Perform
TransCanada Corp.	TRP	39.38	487.7	19,206	1.55	1.70	1.86	1.89	17.9	19.1	21.2	20.8	1.33	3.4%	38.50	1.1%	Market Perform
Group Average (Excl. ENF, FCE, GZM, IPL and PIF)									**16.4**	**17.1**	**20.1**	**18.1**		**3.6%**		**4.2%**	

Canadian Electric Utilities

Company	TSX Ticker	Price (C$) 5-Dec-06	Shares O/S (mm)	Market Cap. (mm)	Earnings per Share 2004A	2005A	2006E	2007E	P/E Ratios 2004A	2005A	2006E	2007E	Dividend Rate	Yield	12-Month Target	Total Return	Rating
Caribbean Utilities Co. Ltd.[2, 3]	CUP.U	$12.44	25.2	$314	$0.77	$0.13	$0.87	$0.87	16.1	NMF	14.3	14.4	$0.66	5.3%	$13.00	9.8%	Outperform
Emera Inc.	EMA	22.91	110.4	2,528	1.16	1.04	1.15	1.14	15.7	18.2	19.9	20.1	0.89	3.9%	22.00	-0.1%	Market Perform
Fortis Inc.	FTS	28.80	103.4	2,979	0.99	1.10	1.28	1.39	15.6	18.6	22.5	20.7	0.78	2.7%	29.25	4.3%	Market Perform
Group Average									**15.8**	**18.4**	**18.9**	**18.4**		**4.0%**		**4.7%**	

Canadian Multi-Utilities

Company	TSX Ticker	Price (C$) 5-Dec-06	Shares O/S (mm)	Market Cap. (mm)	Earnings per Share 2004A	2005A	2006E	2007E	P/E Ratios 2004A	2005A	2006E	2007E	Dividend Rate	Yield	12-Month Target	Total Return	Rating
ATCO Ltd.[1]	ACO/X	$48.73	51.8	$2,525	$2.17	$2.46	$3.13	$2.77	11.7	14.4	15.6	17.6	$0.82	1.7%	NA	NA	NR
Atlantic Power Corporation[6]	ATP.UN	10.00	46.4	464	(0.57)	(0.01)	0.02	0.23	NMF	13.2	16.6	14.0	1.06	10.6%	$10.00	10.6%	Market Perform
Boralex Power Income Fund	BPT.UN	8.55	59.1	505	0.50	0.50	0.55	0.50	21.1	21.5	15.6	17.1	0.90	10.5%	9.00	15.8%	Market Perform
Calpine Power Income Fund	CF.UN	10.89	61.7	672	0.81	0.76	R	R	13.5	13.3	R	R	R	R	R	R	Restricted
Cdn Hydro Developers, Inc.	KHD	5.80	120.5	699	0.06	0.00	0.06	0.07	44.4	NMF	99.1	86.6	0.00	0.0%	5.60	-3.4%	Market Perform
Canadian Utilities Ltd.	CU	46.19	126.6	5,849	1.98	2.03	2.59	2.57	14.4	17.4	17.8	18.0	1.20	2.6%	42.00	-6.5%	Market Perform
Creststreet Power & Income Fund LP	CRS.UN	4.40	11.5	51		(0.54)	(0.00)	0.02		NMF	NMF	NMF	0.65	14.8%	4.25	11.4%	Underperform
EPCOR Power, L.P.	EP.UN	24.84	48.4	1,203	2.25	1.83	1.81	1.27	15.1	19.2	13.7	19.5	2.52	10.1%	25.50	12.8%	Market Perform
Great Lakes Hydro Income Fund	GLH.UN	18.75	48.3	905	1.03	0.75	1.08	1.03	16.5	25.0	17.3	18.2	1.25	6.7%	16.25	-6.7%	Underperform
Innergex Power Income Fund	IEF.UN	12.03	24.7	297	0.46	0.46	0.54	0.47	25.5	28.5	22.4	25.6	0.98	8.1%	11.50	3.7%	Market Perform
Northland Power Income Fund	NPI.UN	12.20	62.1	757	0.57	0.91	0.61	0.73	21.5	13.4	20.0	16.7	1.08	8.9%	13.00	15.4%	Outperform
Maxim Power Corp.[1]	MXG	6.80	43.9	299	0.50	0.30	0.21	0.24	7.6	24.3	32.4	28.3	0.00	0.0%	NA	NA	NR
TransAlta Corp.	TA	25.61	200.6	5,137	0.62	0.88	1.01	1.20	27.6	24.1	25.3	21.3	1.00	3.9%	22.00	-10.2%	Underperform
TransAlta Power L.P.	TPW.UN	7.10	75.1	533	0.48	(0.04)	0.49	0.37	19.8	NMF	14.4	19.0	0.80	11.2%	6.50	2.7%	Underperform
Group Average (Excl. KHD, MXG, IPS, LPs and Income Trusts)									**17.9**	**18.6**	**19.6**	**19.0**		**2.7%**		**-8.3%**	

Notes:
NA = Not Applicable, NMF = Not Meaningful, NR = Not Rated
[1] Estimates from First Call
[2] All figures in U.S. Dollars
[3] Caribbean Utilities' year-end is April 30
[4] Gaz Metro's year-end is Sept. 30
[5] Ticker on the New York Stock Exchange
[6] Represents Income Participating Securities (IPS). Share price, Market Cap and Dividend in C$; all else in US$.
Source: BMO Capital Markets

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Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

I, Michael McGowan, CA, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

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Pollution Probe Interrogatory #10

Ref: Ex. C2-T1-S1, Footnote 10, page 23

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

How does the risk of a utility relative to the market index (i.e. the utility's beta) change when there is an increase in the volatility of the equity market?

Response

Utilities' relative risk, as measured by beta, is more likely to decrease in a period of overall market volatility. On the other hand, the required market return and the equity market risk premium may both increase.

Pollution Probe Interrogatory #11

Ref: Ex. C2-T1-S1, footnote 10, page 25

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Derivations of the CAPM are attributed to Professors Sharpe, Lintner and Mossin. In which of these derivations does it state that the "focus is on the minimum return that will allow a company to attract equity capital"?

Response

In none of the derivations is that statement made. The conclusion that the "focus is on the minimum return that will allow a company to attract equity capital" is a reasonable characterization of a CAPM-derived return given the manner in which it is estimated.

Pollution Probe Interrogatory #12

Ref: Ex. C2-T1-S1, page 26

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

In the first two paragraphs, Ms. McShane argues that allowing capital which was previously captive in Canada to be invested in foreign markets increased domestic returns. If there is captive domestic demand for limited domestic supply of Canadian equities, please have Ms. McShane explain how this leads to lower realized returns.

Response

The referenced paragraphs do not intend to imply that captive demand led to lower realized returns. The point was that Canadian investors could have achieved higher returns investing outside of Canada. Please see response to L-12-32.

Pollution Probe Interrogatory #13

Ref: Ex. C2-T1-S1, page 28

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane provide all of the evidence/materials that she is aware of to support the following statement: "Consequently, I focused on post-World War II returns, that is, 1947-2006, a period more closely aligned with what today's investors are likely to anticipate over the longer-term".

(b) Does Ms. McShane believe that bond investors over the long-term going forward will systematically underestimate expected inflation for periods of ten years or more? Please explain.

(c) Does Ms. McShane believe that investors over the long-term going forward will anticipate a period where pent-up consumer demand caused by a world war will need to be satisfied, as occurred in the early part of the 1947-2006 period? Please explain.

Response

(a) Please see Ex. C2-T1-S1, page 28, footnote 18, which references the key structural changes that occurred since World War II. In Canada, specifically, 1947 coincides with the discovery of oil in Western Canada, and the beginning of a transformation of the economy.

(b) Ms. McShane cannot predict whether this will be the case or not. Investor behaviour is unpredictable and sometimes suggests that investors have not learned from past mistakes, as illustrated by the existence of market "bubbles".

(c) Ms. McShane's objective was to select a time period that was long enough to capture the various types of events, each of which may or may not recur (e.g., the period of high inflation during the late 1970s and 1980s) while at the same time focusing on a period that, on balance, is reflective of the characteristics of today's economy. On its own the economic activity of the first few years after World War II and the impact on equity market returns is not necessarily more or less representative of what may happen in the future as regards equity market performance than any other sub-period dating from 1947. (The first five years of this period, 1947 to 1951, also included three periods identified by the *Canadian Economic Observer* as recessions.)

Pollution Probe Interrogatory #14

Ref: Ex. C2-T1-S1, page 29

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

In using the historic average risk premiums for the U.S. and U.K. presented on this page:

(a) What adjustment did Ms. McShane make for any differences in risk of these market proxies compared with the market proxy she uses for Canada? Please explain.

(b) What adjustment did Ms. McShane make for the foreign exchange risk premium that Canadian investors would require for investing in either of these two foreign markets? Please explain.

Response

(a) She did not make any adjustments. The standard deviation of the returns for Canada and the U.S. are virtually identical over the 1947 - 2006 period. The U.K. returns were not relied on in any formal way, and thus there was no reason to make an adjustment.

(b) She did not make any adjustment for foreign exchange risks. Foreign exchange risk can be diversified or hedged. The average return on U.S. stocks in Canadian dollars over the 1947 - 2006 period (as per the data provided in the Canadian Institute of Actuaries' *Report on Canadian Economic Statistics 1924 - 2006*) was 13.4 percent versus the 13.2 percent average of the U.S. stock returns reported in U.S. dollars as per Ms. McShane's Ex. C2-T1-S1, Schedule 3, page 217.

Pollution Probe Interrogatory #15

Ref: Ex. C2-T1-S1, page 29

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane explain how the geometric average removes uncertainty.

(b) If we have two return series but one return series has more variability, will they have the same geometric mean? Please explain.

Response

(a) The geometric average does not literally remove uncertainty; it masks the degree of volatility or risk that was experienced in year-to-year returns.

(b) It depends on the specifics of the two series. The example below provides two series of returns that ended up having the same geometric return, but Series B was more variable, and thus reflects greater risk.

Year	Series A		Series B	
	Return	Value	Return	Value
Year 0	-	$1.00	-	$1.00
Year 1	10%	$1.10	15%	$1.15
Year 2	10%	$1.21	-20%	$0.92
Year 3	10%	$1.331	+25%	$1.15
Year 4	10%	$1.464	-5%	$1.0925
Year 5	10%	$1.611	+47.5%	$1.611

Pollution Probe Interrogatory #16

Ref: Ex. C2-T1-S1, page 30

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane identify the "studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past". If these studies are not readily accessible to others, please also provide copies of the studies.

(b) Please have Ms. McShane identify the studies that hypothesize that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. If these studies are not readily accessible to others, please also provide copies of the studies.

(c) Please have Ms. McShane confirm that the hypothesis in part (b) relates to an increase in the price/dividend (D/P) ratio and not the P/E ratio.

(d) As contained in footnote 158 on page 176 of her evidence, please have Ms. McShane confirm that concern about the price/dividend ratio was one of two primary factors that she believes led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

Response

(a) The studies are attached:

1. Robert D. Arnott and Peter L. Bernstein, "What Risk Premium is 'Normal'?, *AIMR*, 2000

2. Robert D. Arnott and Ronald J. Ryan, "The Death of the Risk Premium", *The Journal of Portfolio Management*, Spring 2001

3. John Y. Campbell, "Forecasting US Equity Returns in the 21st Century", Harvard University, July 2001

4. James Claus and Jacob Thomas, "Equity Premia as Low as Three Percent? Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Markets", *The Journal of Finance*, October 2001

5. Eugene F. Fama and Kenneth R. French, “The Equity Premium”, The J*ournal of Finance*, April 2002

6. Roger G. Ibbotson and Peng Chen, “Long-Run Stock Returns: Participating in the Real Economy”, *AIMR*, 2003

7. Jeremy J. Siegel, “The Shrinking Equity Premium”, *The Journal of Portfolio Management*, Fall 1999

(b).All the articles provided in response to (a) refer to the increase in price/earnings ratios.

(c) The studies referenced in (b) reference both price/earnings and price/dividend ratios.

(d) Confirmed, but the specific reference in Fed Chairman Greenspan’s 1996 speech was to the price/earnings ratio. The references to price/dividend and Q ratios were attributed to Greenspan in 1999.

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What Risk Premium Is "Normal"?

Robert D. Arnott and Peter L. Bernstein

The goal of this article is an estimate of the objective forward-looking U.S. equity risk premium relative to bonds through history—specifically, since 1802. For correct evaluation, such a complex topic requires several careful steps: To gauge the risk premium for stocks relative to bonds, we need an expected real stock return and an expected real bond return. To gauge the expected real bond return, we need both bond yields and an estimate of expected inflation through history. To gauge the expected real stock return, we need both stock dividend yields and an estimate of expected real dividend growth. Accordingly, we go through each of these steps. We demonstrate that the long-term forward-looking risk premium is nowhere near the level of the past; today, it may well be near zero, perhaps even negative.

The investment management industry thrives on the expedient of forecasting the future by extrapolating the past. As a consequence, U.S. investors have grown accustomed to the idea that stocks "normally" produce an 8 percent real return and a 5 percent (that is, 500 basis point) risk premium over bonds, compounded annually over many decades.[1] Why? Because long-term historical returns have been in this range with impressive consistency. And because investors see these same long-term historical numbers year after year, these expectations are now embedded in the collective psyche of the investment community.[2]

Both the return and the risk premium assumptions are unrealistic when viewed from current market levels. Few have acknowledged that an important part of the lofty real returns of the past stemmed from rising valuation levels and from high dividend yields, which have since diminished. As we will demonstrate, the long-term forward-looking risk premium is nowhere near the 5 percent level of the past; indeed, today, it may well be near zero, perhaps even negative. Credible studies in and outside the United States are challenging the flawed conventional view. Well-researched studies by Claus and Thomas (2001) and Fama and French (2000) are just two (see also Arnott and Ryan 2001). Similarly, the long-term forward-looking real return from stocks is nowhere near history's 8 percent. We argue that, barring unprecedented economic growth or unprecedented growth in earnings as a percentage of the economy, real stock returns will probably be roughly 2–4 percent, similar to bond returns. In fact, even this low real return figure assumes that current near-record valuation levels are "fair" and likely to remain this high in the years ahead. "Reversion to the mean" would push future real returns lower still.

Furthermore, if we examine the historical record, neither the 8 percent real return nor the 5 percent risk premium for stocks relative to government bonds has ever been a realistic *expectation*, except from major market bottoms or at times of crisis, such as wartime. But this topic merits careful exploration. After all, according to the Ibbotson Associates data, equity investors earned 8 percent real returns and stocks have outpaced bonds by more than 5 percent over the past 75 years. Intuition suggests that investors should not require such outsized returns in order to bear equity market risk. Should investors have expected these returns in the past, and why shouldn't they continue to do so? We examine these questions expressed in a slightly different way. First, can we derive an objective estimate of what investors had good reasons to expect in the past? Second, why should we expect less in the future than we have earned in the past?

The answers to both questions lie in the difference between the *observed* excess return and the *prospective* risk premium, two fundamentally different concepts that, unfortunately, carry the same label—risk premium. If we distinguish between past excess returns and future expected risk premiums, the idea that future risk premiums should be different from past excess returns is not at all unreasonable.[3]

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This complex topic requires several careful steps if it is to be evaluated correctly. To gauge the risk premium for stocks relative to bonds, we need an expected real bond return and an expected real stock return. To gauge the expected real bond return, we need both bond yields and an estimate of expected inflation through history. To gauge the expected real stock return, we need both stock dividend yields and an estimate of expected real dividend growth. Accordingly, we go through each of these steps, in reverse order, to form the building blocks for the final goal—an estimate of the objective forward-looking equity risk premium relative to bonds through history.

Has the Risk Premium Natural Limits?

For equities to have a zero or negative risk premium relative to bonds would be unnatural because stocks are, on average over time, more volatile than bonds. Even if volatility were not an issue, stocks are a secondary call on the resources of a company; bondholders have the first call. Because the risk premium is usually measured for corporate stocks as compared with government debt obligations (U.S. T-bonds or T-bills), the comparison is even more stark. Stocks should be priced to offer a superior return relative to *corporate* bonds, which should offer a premium yield (because of default risk and tax differences) relative to T-bonds, which should typically offer a premium yield (because of yield-curve risk) relative to T-bills. After all, long bonds have greater duration—hence, greater volatility of price in response to yield changes—so a capital loss is easier on a T-bond than on a T-bill.

In other words, the current circumstance, in which stocks appear to have a near-zero (or negative) risk premium relative to government bonds, is abnormal in the extreme. Even if we add 100 bps to the risk premium to allow for the impact of stock buybacks, today's risk premium relative to the more relevant corporate bond alternatives is still negligible or negative. This facet was demonstrated in Arnott and Ryan and is explored further in this article.

If zero is the natural minimum risk premium, is there a natural maximum? Not really. In times of financial distress, in which the collapse of a nation's economy, hyperinflation, war, or revolution threatens the capital base, expecting a large reward for exposing capital to risk is not unreasonable. Our analysis suggests that the U.S. equity risk premium approached or exceeded 10 percent during the Civil War, during the Great Depression, and in the wake of World Wars I and II. That said, however, it is difficult to see how one might objectively measure the forward-looking risk premium in such conditions.

A 5 percent excess return on stocks over bonds compounds so mightily over long spans that most serious fiduciaries, if they believed stocks were going to earn a 5 percent risk premium, would not even consider including bonds in a portfolio with a horizon of more than a few years: The probabilities of stocks outperforming bonds would be too high to resist.[4] Hence, under so-called normal conditions—encompassing booms and recessions, bull and bear markets, and "ordinary" economic stresses—a good explanation is hard to find for why expected long-term real returns should ever reach double digits or why the expected long-term risk premium of stocks over bonds should ever exceed about 5 percent. These upper bounds for expected real returns or for the risk premium, unlike the lower bound of zero, are "soft" limits; in times of real crisis or distress, the sky's the limit.

Expected versus "Hoped-For" Returns

Throughout this article, we deal with *expected* returns and *expected* risk premiums. This concept is rooted in objective data and defensible expectations for portfolio returns, rather than in the returns that an investor might *hope* to earn. The distinction is subtle; both represent expectations, but one is objective and the other subjective. Even at times in the past when valuation levels were high and when stockholders would have had no objective reason to expect any growth in real dividends over the long run, hopes of better-than-market short-term profits have always been the primary lure into the game.[5]

When we refer to expected returns or expected risk premiums, we are referring to the estimated future returns and risk premiums that an objective evaluation—based on past rates of growth of the economy, past and prospective rates of inflation, current stock and bond yields, and so forth—might have supported at the time. We explicitly do not include any extrapolation of past returns per se, because past returns are driven largely by changes in valuation levels (e.g., changes in yields), which in an efficient market, investors should not expect to continue into the indefinite future. By the same token, we explicitly do not presume any reversion to the mean, in which high yields or low yields are presumed to revert toward historical norms. We presume that the current yield is "fair" and is an unbiased estimator of future yields, both for stocks and bonds.

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Few investors subjectively expect returns as low as the objective returns produced by this sort of analysis. In a recent study by Welch (2000), 236 financial economists projected, on average, a 7.2 percent risk premium for stocks relative to T-bills over the next 30 years. If we assume that T-bills offer the same 0.7 percent real return in the future that they have offered over the past 75 years, then stocks must be expected to offer a compounded geometric average real return of about 6.6 percent.[6] Given a dividend yield of roughly 1.5 percent in 1998–1999, when the survey was being carried out, the 236 economists in the survey were clearly presuming that dividend and earnings growth will be at least 5 percent a year above inflation, a rate of real growth three to five times the long-term historical norm and substantially faster than plausible long-term economic growth.

Indeed, even if ir vestors take seriously the real return estimates and risk premiums produced by the sort of objective analysis we propose, many of them will continue to believe that their own investments cannot fail to do better. Suppose they agree with us that stocks and bonds are priced to deliver 2–4 percent real returns before taxes.[7] Do they believe that *their* investments will produce such uninspired pretax real returns? Doubtful. If these kinds of projections were taken seriously, markets would be at far different levels from where they are. Consequently, if these objective expectations are correct, most investors will be wrong in their (our?) subjective expectations.

What Were Investors Expecting in 1926

Are we being reasonable to suggest that, after a 75-year span with 8 percent real stock returns and a 5 percent excess return over bonds (the Ibbotson findings), an 8 percent real return or a 5 percent risk premium is abnormal? Absolutely. The relevant question is whether the investors of 1926 would have had reason to *expect* these extraordinary returns. In fact, they would not. What they got was different from what they should have expected, which is a normal result in a world of uncertainty.

At the start of 1926, the beginning of the returns covered in the Ibbotson data, investors had no reason to expect the 8 percent real returns that have been earned over the past 75 years nor that these returns would provide a 5 percent excess return over bonds. As we will describe, these outcomes were the consequence of a series of historical accidents that uniformly helped stocks and/or helped the risk premium.

Consider what investors might objectively have expected at the start of 1926 from their long-term investments in stocks and bonds. In January that year, government bonds were yielding 3.7 percent. The United States was on a gold standard, government was small relative to the economy as a whole, and the price level of consumer goods, although volatile, had been trendless throughout most of U.S. history up to that moment; thus, inflation expectations were nil. It was a time of relative stability and prosperity, so investors would have had no reason to expect to receive less than this 3.7 percent government bond yield. Accordingly, the *real* return that investors would have expected on their government bonds was 3.7 percent, plain and simple.

Meanwhile, the dividend yield on stocks was 5.1 percent. We can take that number as the starting point to apply the sound theoretical notion that the real return on stocks is equal to

- the dividend yield
- plus (or minus) any change in the real dividend (now viewed as participation in economic growth)
- plus (or minus) any change in valuation levels, as measured by P/E multiples or dividend yields.

What did the investors expect of stocks in early 1926? The time was the tail end of the era of "robber baron" capitalism. As Chancellor (1999) observed, investors were accustomed to the fact that company managers would often dilute shareholders' returns if an enterprise was successful but that the shareholder was a full partner in any business decline. More important was the fact that the long-run history of the market was trendless. Thoughts of long-term economic growth, or long-run capital appreciation in equity holdings, were simply not part of the tool kit for return calculations in those days.

Investors generally did not yet consider stocks to be "growth" investments, although a few people were beginning to acknowledge the full import of Smith's extraordinary study *Common Stocks as Long-Term Investments*, which had appeared in 1924. Smith demonstrated how stocks had outperformed bonds over the 1901–22 period.[8] His work became the bible of the bulls as the bubble of the late 1920s progressed. Prior to 1926, however, investors continued to follow J.P. Morgan's dictum that the market would fluctuate, a traditional view hallowed by more than 100 years of stock market history. In other words, investors had no *trend* in mind. The effort was to buy low and to sell high, period.

Assuming that markets were fairly priced in early 1926, investors should have expected little or no benefit from rising valuation levels. Accordingly, the real long-term return that stock investors could reasonably have expected on average, or from

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the market as a whole, was the 5.1 percent dividend yield, give or take a little. Thus, stock investors would have expected roughly a 1.4 percent risk premium over bonds, not the 5 percent they actually earned in the next 75 years. The market exceeded objective expectations as a consequence of a series of historical accidents:

- *Historical accident #1: Decoupling yields from real yields.* The Great Depression (roughly 1929–1939) introduced a revolutionary increase in the role of government in peacetime economic policy and, simultaneously, drove the United States (and just about the rest of the world) off the gold standard. As prosperity came back in a big way after World War II, expected inflation became a normal part of bond valuation. This change created a one-time shock to bonds that decoupled nominal yields from real yields and drove nominal yields higher even as real yields fell. Real yields at year-end 2001 were 3.4 percent (the Treasury Inflation-Indexed Securities, commonly called TIPS, yield[9]), but nominal yields were 5.8 percent. This rise in nominal yields (with real yields holding steady) has cost bondholders 0.4 percent a year over 75 years. That accident alone accounts for nearly one-tenth of the 75-year excess return for stocks relative to bonds.
- *Historical accident #2: Rising valuation multiples.* Between 1926 and 2001, stocks rose from a valuation level of 18 times dividends to nearly 70 times dividends. This fourfold increase in the value assigned to each dollar of dividends contributed 180 bps to annual stock returns over the past 75 years, even though the entire increase occurred in the last 17 years of the period (we last saw 5.1 percent yields in 1984). This accident explains fully one-third of the 75-year excess return.
- *Historical accident #3: Survivor bias.* Since 1926, the United States has fought no wars on its own soil, nor has it experienced revolution. Four of the fifteen largest stock markets in the world in 1900 suffered a total loss of capital, a –100 percent return, at some point in the past century. The markets are China, Russia, Argentina, and Egypt. Two others came close—Germany (twice) and Japan. Note that war or revolution can wipe out bonds as easily as stocks (which makes the concept of "risk premium" less than relevant). U.S. investors in early 1926 would *not* have considered this likelihood to be zero, nor should today's true long-term investor.
- *Historical accident #4: Regulatory reform.* Stocks have gone from passing relatively little economic growth through to shareholders to passing much of the economic growth through to shareholders. This shift has led to 1.4 percent a year growth in real dividend payments and in real earnings since 1926. This accelerated growth in real dividends and earnings, which no one in 1926 could have anticipated, explains roughly one-fourth of the 75-year excess return.[10]

In short, the equity investors of 1926 probably expected to earn a real return little different from their 5.1 percent yield and expected to earn little more than the 140 bp yield differential over bonds. Indeed, an objective investor might have expected a notch less because of the greater frequency with which investors encountered dividend cuts in those days.

What Expectations Were Realistic in the Past?

To gauge what risk premium an investor might have objectively expected in the longer run past, we need to (1) estimate the real return that investors might reasonably have expected from stocks, (2) estimate the real return that investors might reasonably have expected from bonds, and (3) take the difference. From this exercise, we can gauge what risk premium an investor might reasonably have expected at any point in history, not simply an isolated snapshot of early 1926. A brief review of the sources of stock returns over the past two centuries should help lay a foundation for our work on return expectations and shatter a few widespread misconceptions in the process. The sources of the data are given in Appendix A.[11]

Step I: How Well Does Economic Growth Flow into Dividend Growth? Over the past 131 years, since reliable earnings data became available in 1870, the average earnings yield has been 7.6 percent and the average real return for stocks has been 7.2 percent; this close match has persuaded many observers to the view (which is wholly consistent with finance theory) that the best estimate for real returns is, quite simply, the earnings yield. On careful examination, this hypothesis turns out to be wrong. In the absence of changing valuation levels, real returns are systematically *lower* than earnings yields.

Figure 1 shows stock market returns since 1802 in a fashion somewhat different from that shown in most of the literature. The solid line in Figure 1 shows the familiar cumulative total return for U.S. equities since 1802, in which each $100 invested grows, with reinvestment of dividends, to almost $700 million in 200 years. To be sure, some of this growth came from inflation; as the line "Real Stock Return" shows, $700 million will not buy what it

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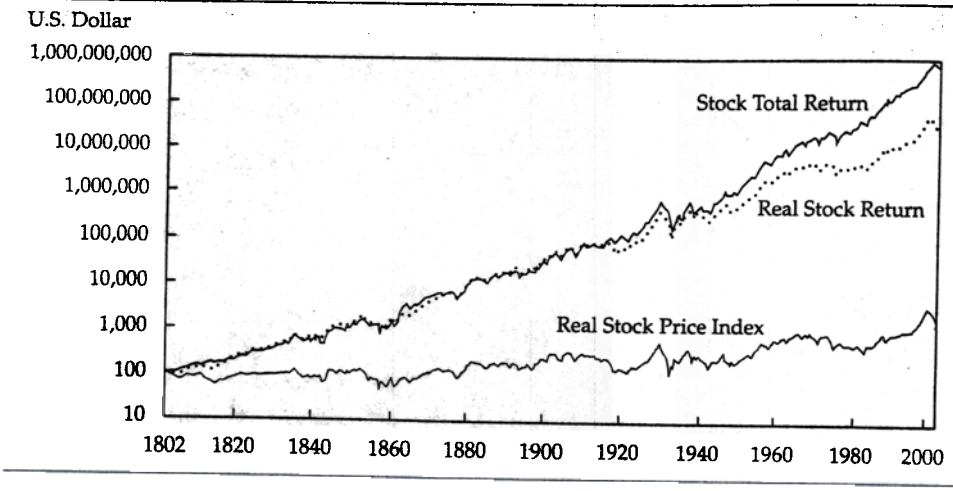
Figure 1. Return from Inflation and Dividends: Growth of $100, 1801–2001

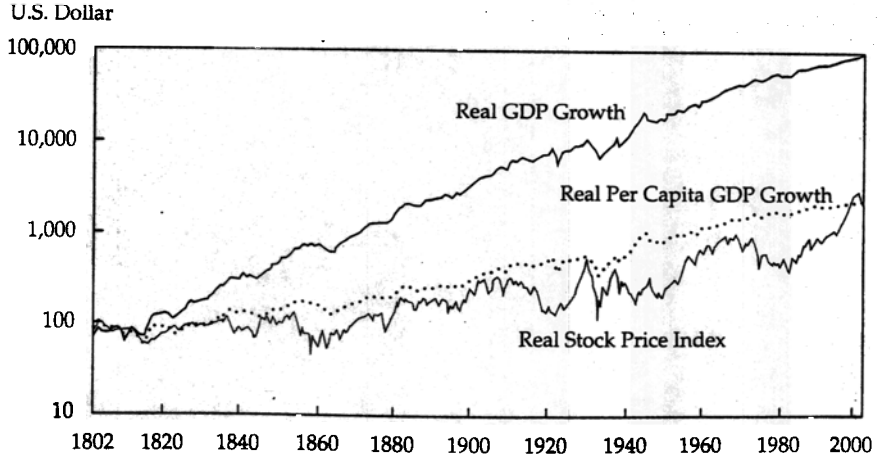


would have in 1802, when one could have purchased the entire U.S. GNP for less than that sum.[12] By removing inflation, we show in the "Real Stock Return" line that the $100 investment grew to "only" $37 million. Thus, adjusted for inflation, our fortune is much diminished but still impressive. Few portfolios are constructed without some plans for future spending, and the dividends that stocks pay are often spent. So, the "Real Stock Price Index" line shows the wealth accumulation from price appreciation alone, net of inflation and dividends. This bottom line (literally and figuratively) reveals that stocks have risen just 20-fold from 1802 levels. Put another way, if an investor had placed $100 in stocks in 1802 and received and spent the average dividend yield of 4.9 percent for the next 200 years, his or her descendants would today have a portfolio worth $2,099, net of inflation. So much for our $700 million portfolio!

Worse, the lion's share of the growth from $100 to $2,099 occurred in the massive bull market from 1982 to date. In the 180 years from 1802 to the start of 1982, the real value of the $100 portfolio had grown to a mere $400. If stocks were priced today at the same dividend yields as they were in 1802 and 1982, a yield of 5.4 percent, the $100 portfolio would be worth today, net of inflation and dividends, just $550. These data put the lie to the conventional view that equities derive most of their returns from capital appreciation, that income is far less important, if not irrelevant.

Figure 2 allows a closer look at the link between equity price appreciation and economic growth. It shows that the growth in share prices is much more closely tied to the growth in real *per capita* GDP (or GNP) than to growth in real GDP per se. The solid line shows that, compounding at about 4 percent in the 1800s and 3 percent in the 1900s, the economy itself delivered an impressive 1,000-fold growth.

Figure 2. The Link between Stock Prices and Economic Growth, 1802–2001



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But net of inflation and dividend distributions, stock prices (the same "Real Stock Price Index" line in Figure 1) fell far behind, with cumulative real price appreciation barely 1/50 as large as the real growth in the economy itself.

How can this be? Can't shareholders expect to participate in the growth of the economy? No. Shareholders can expect to participate *only in the growth of the enterprises they are investing in.* An important engine for economic growth is the creation of new enterprises. The investor in today's enterprises does not own tomorrow's new enterprises—not without making a separate investment in those new enterprises with new investment capital.

Finally, the "Real Per Capita GDP Growth" line in Figure 2 shows the growth of the economy measured net of inflation *and population growth.* This growth in real per capita GDP tracks much more closely with the real price appreciation of stocks (the bottom line) than does real GDP itself.

Going one step further, **Figure 3** shows the internal growth of real dividends—that is, the growth that an index fund would expect to see in its own real dividends in the absence of additional investments, such as reinvestment of dividends.[13] Real dividends exhibit *internal* growth that is similar to the growth in real per capita GDP. Because growth in per capita GDP is a measure of productivity growth, the internal growth that can be sustained in a diversified market portfolio should closely match the growth of *productivity* in the economy, not the growth in the economy per se. Therefore, the dotted line traces per capita real GDP growth, the "Real Stock Price Index" line shows real stock prices, and the bottom line shows real dividends (× 10).[14] Figure 3 reveals the remarkable resemblance between real dividend growth and growth in real per capita GDP.

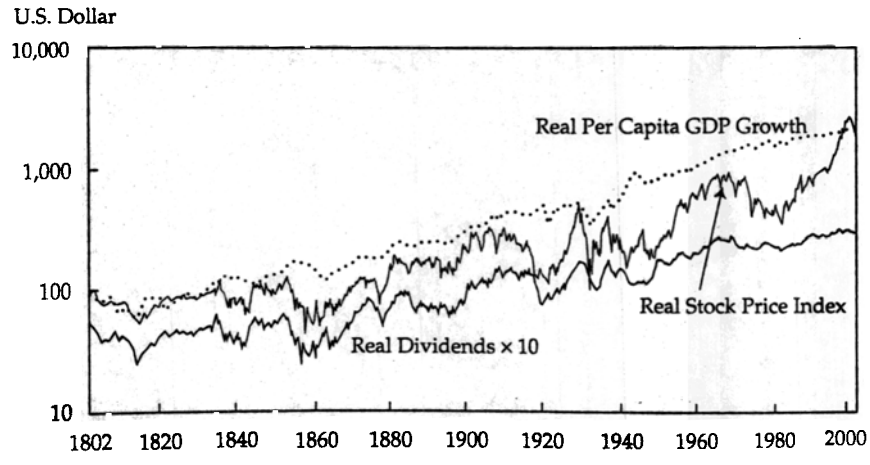
When we measure the internal growth of real dividends as in Figure 3, we see that real dividends have risen a modest fivefold from 1802 levels. In other words, the real dividends for a $100 portfolio invested in 1802 have grown merely 0.9 percent a year net of inflation. To be sure, the price assigned to each dollar of dividends has quadrupled, which leads to the 20-fold real price gain in the 200 years.

Although real dividends have tracked remarkably well with real per capita GDP, they have consistently fallen short of GDP gains. Not only have real dividends failed to match real GDP growth (as many equity investors seem to think is a *minimal* future growth rate for earnings and dividends), they have even had a modest shortfall, at an average of about 70 bps a year, relative to per capita economic growth.

In short, more than 85 percent of the return on stocks over the past 200 years has come from (1) inflation, (2) the dividends that stocks have paid, and (3) the rising valuation levels (rising P/Es and falling dividend yields) since 1982, not from growth in the underlying fundamentals of real dividends or earnings.[15] Furthermore, real dividends and real per capita GDP both grew faster in the 20th century than in the 19th century. Conversely, GDP grew faster in the 19th century than in the 20th century, *unless* we convert to per capita GDP.

Many observers think that earnings growth is far more important than dividend growth. We respectfully disagree. As noted by Hicks (1946), "... any increase in the present value of prospective net receipts must raise profits." In other words, properly stated, earnings should represent a proportional share of the net present value of all future

Figure 3. Dividends and Economic Growth, 1802–2001



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profits. The problem is that reported earnings often do not follow this theoretical definition. For example, negative earnings should almost never be reported, yet reported operating losses are not uncommon. Furthermore, the quality of earnings reports prior to the advent of the U.S. SEC is doubtful at best; worse, we were unable to find any good source for earnings information prior to 1870. Accordingly, the dividend is the one reliable aspect of stock ownership over the past two centuries. It is the cash income returned to the shareholders; it is the means by which the long-term investor earns most of his or her internal rate of return. Finally, with earnings growth barely 0.3 percent faster than dividend growth over the past 131 years, an analysis based on earnings would reach conclusions nearly identical to our conclusions based on dividends.

Finance theory tells us that capital is fungible; that is, equity and debt, retained earnings and dividends—all should flow to the best use of capital and should (in the absence of tax-related arbitrages and other nonsystematic disruptions) produce a similar risk-adjusted return on capital. Thus, the retained earnings should deliver a return similar to the return an investor could have earned on that capital had it been paid out as dividends. Consider an example: If a company has an earnings yield of 5 percent (corresponding to a P/E of 20), it can pay out all of the earnings and thereby deliver a 5 percent yield to the shareholder. The real value of the company should not be affected by this full earnings distribution (unless the earnings are themselves being misstated), so the 5 percent earnings yield should also be the expected real return. Now, if the company, instead, pays a 2 percent yield and retains earnings worth 3 percent of the stock price, the company ought to achieve 3 percent real growth in earnings; otherwise, it should have distributed the cash to the shareholders. How does this theory stand up to reality?

Over the past 200 years, dividend yields have averaged 4.9 percent, yet real returns have been far higher, 6.6 percent. Since 1870, earnings yields have averaged 7.6 percent, close to the real returns of 7.2 percent over that span. This outcome is consistent with the notion of fungible capital, that the return on capital reinvested in an enterprise ought to match the return an investor might otherwise have earned on that same capital if it had been distributed as a dividend. However, if we take out the changes in valuation levels since 1982 (regardless of whether dividend yields or P/Es are used for those levels), the close match between earnings yield and real stock returns evaporates.

Moreover, with an average earnings yield of 7.6 percent and an average dividend yield of 4.7 percent since 1871, the average "retained earnings yield" has been nearly 3 percent. This retained earnings yield should have led to real earnings and dividend growth of 3 percent; otherwise, management ought to have paid this money out to the shareholders. Instead, real dividends and earnings grew at annual rates of, respectively, 1.2 percent and 1.5 percent. Where did the money go? The answer is that during the era of "pirate capitalism," success often led to dilution: Company managers issued themselves more stock![16]

Furthermore, retained earnings often chase poor internal reinvestment opportunities. If existing enterprises experienced only 1.2–1.5 percent internal growth of real dividends and earnings in the past two centuries, most of the 3.6 percent economic growth the United States has enjoyed has clearly not come from reinvestment in existing enterprises. In fact, it has stemmed from entrepreneurial capitalism, from the creation of new enterprises. Indeed, dividends on existing enterprises have fallen relative to GDP growth by approximately 100-fold in the past 200 years.[17]

The derring-do of the pirate capitalists of the 19th and early 20th centuries is not the only or even the most compelling explanation for this phenomenon. All the data we used are from indexes, which are a particular kind of sampling of the market. Old companies fading from view lose their market weight as the newer and faster growing companies gain a meaningful share in the economy. The older enterprises often have the highest earnings yield and the worst internal reinvestment opportunities, but the new companies do not materialize in the indexes the minute they start doing business or even the minute they go public. When they do enter the index, their starting weight is often small.

Furthermore, an index need only change the divisor whenever a new enterprise is added, whereas we cannot add a new enterprise to our portfolio without cost. The index changing the divisor is mathematically the same as selling a little bit of *all other* holdings to fund the purchase of a new holding, but when we add a new enterprise to our portfolios, we must commit some capital to effect the purchase. Whether through reinvestment of dividends or infusion of new capital, this new enterprise cannot enter our portfolio through the *internal* growth of an existing portfolio of assets. In effect, we must rebalance out of existing stocks to make room for the new stock—which produces the natural dilution that takes place as a consequence of the creation of new enterprises in a world of entrepreneurial capitalism: The same dollar cannot own an existing enterprise and simultaneously fund a new enterprise.[18]

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The dynamics of the capitalist system inevitably lead to these kinds of results. Good business leads to expansion; in a competitive environment, expansion takes place on a wide scale; expansion on a wide scale intensifies the competitive environment; margins begin to decline; earnings growth slows; in time, earnings begin to decline; then, expansion slows, profit margins improve, and the whole thing repeats itself. We can see this drama playing out in the relationship between payout ratios in any given year and earnings growth: Since 1984, the payout ratio has explained more than half of the variation in five-year earnings growth rates with a *t*-statistic of 9.51.[19]

Few observers have noticed that much of the difference between stock dividend yields and the real returns on stocks can be traced directly to the upward revaluation of stocks since 1982. The historical data are muddied by this change in valuation levels—which is why we find the current fashion of forecasting the future by extrapolating the past to be so alarming. The earnings yield is a better estimate of future real stock returns than any extrapolation of the past. And the dividend yield plus a small premium for real dividend growth is even better, because in the absence of changes in valuation levels, the earnings yield systematically overstates future real stock returns.

If long-term real growth in dividends had been 0.9 percent, real stock returns would have been only 90 bps higher than the dividend yield if it were not for the enormous jump in the price-to-dividend ratio since 1982. Even if we adjust today's 1.4 percent dividend yield sharply upward to include "dividends by another name" (e.g., stock repurchases), making a case for real returns higher than the 3.4 percent currently available in the TIPS market would be a stretch.[20]

Step II: Estimating Real Stock Returns. To estimate the historical equity risk premium, we must compare (1) a realistic estimate of the *expected* real stock return that objective analysis might have supported in past years with (2) the *expected* real bond return available at the time. Future long-term real stock return is defined as[21]

$$RSR(t) = DY(t) + RDG(t) + \Delta PD(t) + \varepsilon, \quad (1)$$

where

$DY(t)$ = percentage dividend yield for stocks at time t

$RDG(t)$ = percentage real dividend growth rate over the applicable span starting at time t

$\Delta PD(t)$ = percentage change in the price assigned to each dollar of dividends starting at time t

ε = error term for sources of return not captured by the three key constituents (this term will be small because it will reflect only compounding effects)

Viewed from the perspective of forecasting future real returns, the $\Delta PD(t)$ term is a valuation term, which we deliberately exclude from our analysis. If markets exhibit reversion to the mean, valuation change should be positive when the market is inexpensive and negative when the market is richly priced. If markets are efficient, this term should be random. We choose not to go down the slippery slope of arguing valuation, even though we believe that valuation matters. Rather, we prefer to make the simplifying assumption that market valuations at any stage are "fair" and, therefore, that the real return stems solely from the dividend yield and real growth of dividends.

That said, the estimation process becomes more complex when we consider a sensible estimate for real dividend growth. For example, what real dividend growth rate might an investor in 1814 have expected on the heels of the terrible 1802–14 bear market and depression, during which real per capita GDP, real dividends, and real stock prices all contracted 40–50 percent? How can we objectively put ourselves in the position of an investor almost 200 years ago? For this purpose, we partition the real growth in dividends into two constituent parts, real economic growth and the growth of dividends relative to the economy.

Why not simply forecast dividend growth directly? Because countless studies have shown that analysts' forecasts are too optimistic, especially at market turning points. In fact, dividends (and earnings) in aggregate cannot grow as fast as the economy on a sustainable long-term basis, in large part because of the secular increase in shares outstanding and introduction of new enterprises. So, long-term dividend growth should be equal to long-term economic growth minus a haircut for dilution or entrepreneurial capitalism (the share of economic growth that is tied to new enterprises not yet available in the stock market) or plus a premium for hidden dividends, such as stock buybacks. So, real dividend growth is given by

$$RDG(t) = RGDP(t) + DGR(t) + \varepsilon, \quad (2)$$

where

$RGDP(t)$ = percentage real per capita GDP growth over the applicable span starting at time t

$DGR(t)$ = annual percentage dilution of real GDP growth as it flows through to real dividends starting at time t

ε = error term for compounding effects (it will be small)

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Basically, in Equation 2, we are substituting $RGDP(t) + DGR(t)$ for $RDG(t)$ and rolling the $\Delta PD(t)$ term into the error term (to avoid getting into the debates about valuation and regression to the mean). With these two changes, and converting to an expectations model, our model for expected real stock market returns, *ERSR*, becomes

$$ERSR(t) = EDY(t) + ERGDP(t) + EDGR(t), \quad (3)$$

where

$EDY(t)$ = *expected* percentage dividend yield for stocks at time t

$ERGDP(t)$ = *expected* percentage real per capita GDP growth over the applicable span starting at time t

$EDGR(t)$ = *expected* annual percentage dilution of real per capita GDP growth as it flows through to real dividends starting at time t

A complication in this structure is the impact of recessions. In serious recessions, dividends are cut and GDP growth stops or reverses, possibly leading to a decline in even the long-term GDP growth. The result is a dividend yield that is artificially depressed, real per capita GDP growth that is artificially depressed, and long-term dividend growth relative to GDP growth that is artificially depressed, all three of which lead, in recessionary troughs, to understated expected real stock returns. The simplest way to deal with this issue is to use the last peak in dividends before a business downturn and the last peak in GDP before a business downturn in computing each of the three constituents of expected real stock returns.[22]

We illustrate how we constructed an objective real stock return forecast for the past 192 years in **Figure 4**; Panel A spans 1810 to 2001, and Panel B shows the same data after 1945. To explain these graphs, we will go through them line by line.

The easiest part of forecasting real stock returns, the "Estimated Real Stock Return" line in Figure 4, is the dividend yield: It is a known fact. We have adjusted dividends to correct for the artificially depressed dividends during recessions to get the $EDY(t)$ term shown as the "Dividend Yield" line in Figure 4. This step allows us to avoid understating the equity risk premium in recessions when dividends are artificially depressed. This adjustment boosts the expected dividend yield slightly relative to the raw dividend yield because the deepest recessions are often deeper than the average recessions of the prior 40 years. Against an average dividend yield of 4.9 percent, we found an average *expected* dividend yield of 5.0 percent.

Most long-run forecasts of earnings or dividend growth ignore the simple fact that aggregate earnings and dividends in the economy cannot sustainably grow faster than the economy itself. If new enterprise creation and secondary equity offerings dilute the share of the economy held by the shareholders in existing enterprises, then one sensible way to forecast dividend growth is to forecast economic growth and then forecast how rapidly this dilution will take place.[23] Stated another way, we want to know how much *less* rapidly dividends (and earnings) on existing enterprises can grow than the economy at large. The sum of real economic growth less this shortfall is the real growth in dividends.

The resulting line, "Dilution of GDP Growth in Dividends," in the two graphs of Figure 4 represents the $EDGR(t)$ term in our model (Equation 3). Note the persistent tendency for dividend growth to lag GDP growth: Real dividends have grown at 1 percent a year over the past 192 years, whereas the real economy has grown at 3.8 percent a year, and even real per capita GDP has grown at 1.8 percent a year. Why should real dividends have grown so much more slowly than the economy?

First, much of the growth in the economy has come from innovation and entrepreneurial capitalism. More than half of the capitalization of the Russell 3000 today consists of enterprises that did not exist 30 years ago. The 1971 buy-and-hold investor could not participate in this aspect of GDP growth or market growth because the companies did not exist. So, today's dividends and earnings on the existing companies from 1971 are only part of the dividends and earnings on today's total market.

Second, as was demonstrated in Bernstein (2001b), retained earnings are often not reinvested at a return that rivals externally available investments; earnings and dividend growth are faster when payout ratios are high than when they are low, perhaps because corporate managers are then forced to be more selective about reinvestment alternatives.[24]

Finally, as we have emphasized, corporate growth typically leads to more shares outstanding, which automatically imposes a drag on the growth in dividends per share.

As a sensible estimate of the future dividend/GDP shortfall, the rational investor of any day might forecast dividend growth by using the prior 40-year shortfall in dividend growth relative to per capita GDP or might choose to use the cumulative (by now, 200-year) history. We chose the simple expedient of averaging the two.

The dilution effect we found from the 40-year and cumulative data for real dividends and real per capita GDP averages –60 bps. So, in the past 40 years, the dilution of dividend growth is almost

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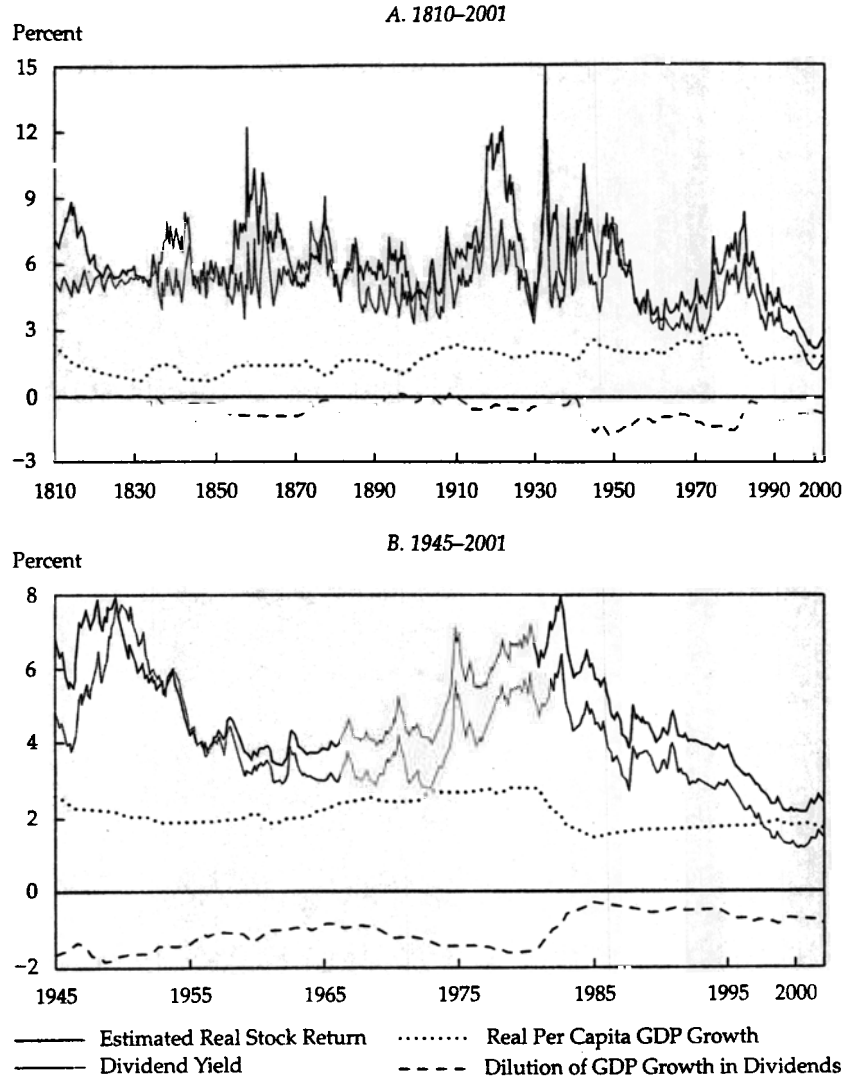
Figure 4. Estimating Real Stock Returns



exactly the same as the long-term average, –80 bps. With a standard deviation of just 0.5 percent, this shortfall of dividend growth relative to economic growth is the steadiest of any of the components of real stock returns or real bond returns. It has never been materially positive on a long-term sustained basis; it has never risen above +10 bps for any 40-year span in the entire history since 1810.

The history of dividend growth shows no evidence that dividends can ever grow materially faster than per capita GDP. Indeed, they almost always grow more slowly. Suppose real GDP growth in the next 40 years is 3 percent a year and population growth is 1 percent a year. These assumptions would appear to put an *upper limit* on real dividend growth at a modest 2 percent a year, far below consensus expectations. If the historical average dilution of dividend growth relative to real per capita GDP growth prevails, then the future real growth in dividends should be only about 1 percent, even with relatively robust, 2.5–3.0 percent, real GDP growth.

Now consider the third part of forecasting real stock returns in this fashion—the forecast of long-term real per capita GDP growth, *ERGDP(t)* in our model. How much real per capita GDP growth would an investor have expected at any time in the past 200 years? Again, a simple answer might come from the most recent 40 years' growth rate; another might come from the cumulative record going back as far as we have dividend and GDP data, to 1802. These historical data are shown in the "Real per Capita GDP Growth" line in Figure 4. And again, we chose the simple expedient of averaging the average of the two. Real per capita GDP growth has been remarkably stable over the past 200 years, particularly if we adjust it to correct for temporary dips during recessions. If we examine truly long-term

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results, the 40-year real growth rate in real per capita GDP has averaged 1.8 percent with a standard deviation of only 0.9 percent.[25]

Note from Figure 4 that the total economy grew faster during the 19th century than the 20th century whereas stock returns (and the underlying earnings and dividends) grew faster in the 20th century than the 19th. Why would the rapid growth of the 19th century flow through to the shareholder less than the slower growth of the 20th century? We see two possible answers. First, the base from which industrial growth started in the 19th century was so much smaller that much faster new enterprise creation occurred then than in the 20th century. Second, with nearly 3 percent growth in the population from 1800 to 1850, the growing talent and labor pool fueled a faster rate of growth than the 1.25 percent annual population growth rate of the most recent 50 years. It is not surprising that the pace of dilution, both from the creation of new enterprises and from secondary equity offerings, is faster when the population is growing faster. Population growth fuels growth in human capital, in available labor, and in both demand *and* supply of goods and services. As a result, when population growth is rapid, the pace of dilution of growth in the economy (as it flows through to a shareholder's earnings and dividends) is far more stable relative to real per capita GDP than relative to real GDP itself.

The simple framework we have presented for estimating real stock returns reveals few surprises. As Panels A and B of Figure 4 show, the expected stock return is the sum of the three constituent parts graphed in the other lines. We estimate that expected real stock returns for the past 192 years averaged about 6.1 percent with the following constituent parts: an expected yield averaging 5.0 percent plus real per capita GDP growth of 1.7 percent a year minus an expected *shrinkage* in dividends relative to real per capita GDP averaging –0.6 percent. Meanwhile, investors actually earned real returns of 6.8 percent. Most of this 70 bp difference from the 6.1 percent rational expectation over the past 192 years can be traced to the rise in valuation levels since 1982; the rest consists of the other happy accidents detailed previously.

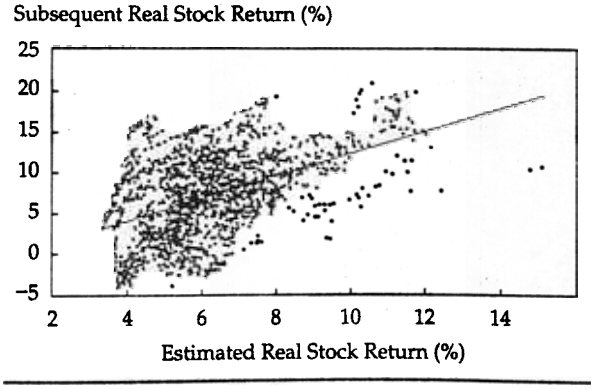
Expectations for real stock returns have soared above 6 percent often enough that many actuaries even today consider 8 percent a "normal" real return for equities. Our estimate for real stock returns, however, exceeds 8 percent only during the depths of the Great Depression, in the rebuilding following the War of 1812, the Civil War, World War I, and World War II, and in the Crash of 1877. In the past 50 years, expected real stock returns above 7 percent have been seen only in the aftermath of World War II, when many investors still feared a return to Depression conditions, and in the depths of the 1982 bear market.

When viewed from the vantage point of this formulation for expected real stock returns, the full 192-year record shows that expected real stock returns fell below 3.5 percent only once before the late 1990s, at the end of 1961 just ahead of the difficult 1962–82 span, real stock prices fell by more than 50 percent. Since 1997, expected real stock returns have fallen well below the 1961 levels, where they remain at this writing.

This formulation for expected real stock returns reveals the stark paradigm shift that took place in the 1950s. Until then, the best estimate for real dividend growth was rarely more than 1 percent, so the best estimate for real stock returns was approximately the dividend yield plus 100 bps—considerably less than the earnings yield! From the 1950s to date, as Panel B of Figure 4 shows, the shortfall of dividends relative to GDP growth improved (perhaps because the presence of the SEC discourages company managers from ignoring shareholder interests) and the real return that one could objectively expect from stocks finally and persuasively rose above the dividend yield. Today, it stands at almost twice the dividend yield, but it is still a modest 2.4 percent.

Figure 5 shows the strong correlation between our formulation for expected real stock returns and the actual real returns that stocks have delivered over the subsequent 10-year span. The correlation is good—at 0.62 during the modern market era after World War II and 0.46 for the full 182 years.[26] If we test the correlation between this simple metric of expected real stock returns and the actual subsequent 20-year real stock returns (not shown), the correlations grow to 0.95 and 0.60 for the post-1945 period and the full 182 years, respectively.

Figure 5. Estimated and Subsequent Actual Real Stock Returns, 1802–2001



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The regression results given in Panel A Table 1 show that the coefficient in the regression is larger than 1.00. So, that 100 bp increase in the expected real stock return, *ERSR*, is worth more than 100 bps in the subsequent 10-year actual real stock return, *RSR*. The implication is that some tendency for reversion to the mean does exist and that it will magnify the effect of unusually high or low expected real stock returns. This suggestion has worrisome implications for the recent record low levels for expected real stock returns.

Because rolling 10-year returns (and expected returns in our model) are highly serially correlated, the *t*-statistics given in Panel A of Table 1 are not particularly meaningful. One way to deal with overlapping data is to eliminate the overlap by using nonoverlapping samples—in this case, examining only our 19 nonoverlapping samples beginning December 1810. The Panel B results, with a coefficient larger than 1.00, confirm the previous results (and approach statistical significance, even with only 17 degrees of freedom).[27] One worrisome fact, in light of the recent large real stock returns, is that the nonoverlapping real stock returns by decades have a –31 percent serial correlation. Although it is not a statistically significant correlation, it is large enough to be interesting: It suggests that spectacular decades or wretched decades may be considerably more likely to reverse than to repeat.

Evaluating the real returns on stocks is clearly a useful exercise if the metric of success for a model is subsequent actual real returns, but we live in a relative world. The future real returns on all assets will rise and fall; so, real returns are an insufficient metric of success. What is of greater import is whether this metric of prospective real stock returns helps us identify the attractiveness of stocks *relative to other assets.*

Step III: Estimating Future Real Bond Returns. On the bond side, real realized returns are equal to the nominal yield minus inflation (or plus deflation) and plus or minus yield change times duration:

$$RBR(t) = BY(t) - INFL(t) + \Delta BY(t)DUR(t) + \varepsilon, \quad (4)$$

where

$BY(t)$ = percentage bond yield at time t

$INFL(t)$ = percentage inflation over the applicable span starting at time t

$\Delta BY(t)DUR(t)$ = annual change in yield over the applicable span times duration at time t (under the assumption that rolling reinvestment is in bonds of similar duration)

ε = error term (compounding effects lead to a small error term in this simple formulation)

As with stocks, we prefer to take current yields as a fair estimate of future bond yields. So, we eliminate the variable that focuses on changes in yields, $\Delta BY(t)DUR(t)$. We also need to shift our focus from measuring past real bond returns to forecasting future real bond returns. Therefore, our model is

$$ERBR(t) = BY(t) - EINFL(t), \quad (5)$$

where $BY(t)$ is the percentage bond yield at time t and $EINFL(t)$ is the expected percentage inflation over the applicable span starting at time t.

Equation 5 is difficult only in the sense that expectations for inflation in past economic environs are difficult to estimate objectively. How, for example, are we to gauge how much inflation an investor in February 1864 would have expected at a time when inflation had averaged 20 percent over the prior three years because of wartime shortages?

Table 1. Regression Results: Estimated Real Stock Return versus Actual 10-Year Real Stock Return
(*t*-statistics in parentheses)

Period	*a*	*b*	R^2	Correlation	Serial Correlation
A. Raw data: RSR(t) = a + b[ERSR(t – 120)]					
1810–2001	–1.51%	1.38%	0.214	0.46	0.992
	(–4.2)	(24.4)			0.990
1945–2001	–7.80	3.15	0.391	0.62	0.996
	(–8.8)	(19.0)			0.995
B. Using 19 nonoverlapping samples, beginning December 1810					
1810–2000	–0.35%	1.22%	0.182	0.430	–0.315
	(–0.1)	(1.9)			0.021

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Expectations would depend strongly on the outcome of the war: A victory by the North would have been expected to result in a restoration of the purchasing power of the dollar as wartime shortages disappeared; a victory by the South could have had severe consequences on the ultimate purchasing power of the North's dollar as a consequence of debt that could no longer be serviced. A rational expectation might have been for inflation greater than 0 (reflecting the possibility of victory by the South) but less than the 20 percent three-year inflation rate (reflecting the probability of victory by the North).

We based the estimate for expected future inflation on an *ex ante* regression forecast of 10-year future inflation based, in turn, on recent three-year inflation.[28] **Figure 6** shows how the expected rate of inflation has steadily become more closely tied to recent actual inflation in recent decades. Bond yields responded weakly to bursts of inflation up until the time of the Great Depression; they responded more strongly as inflation became a structural component of the economy in the past four decades.

Until the last 40 years, inflation was generally associated with wars and was virtually nonexistent—even negative—in peacetime. Figure 6 shows a burst of double-digit inflation on the heels of the War of 1812, in the late stages of the Civil War, during World War I, and in the rebuilding following World War II. And more recently, double-digit inflation characterized the "stagflation" of 1978–1981 that followed the Vietnam War and the oil shocks of the 1970s. The most notable changes since the Great Depression, especially since World War II, involve the magnitude and perceived role of government and loss of the automatic brakes once applied by the gold standard. From the end of World War II to the great inflationary crisis at the end of the 1970s, the dread of unemployment that was inherited from the Great Depression was the driving factor in both fiscal and monetary policy.

With the introduction of TIPS in January 1997, we finally have a U.S. government bond that pays a real return, which allows us to simplify the expected real bond returns to be the TIPS yield itself from that date forward; that is,

$$ERBR(t) = YTIPS(t), \quad (6)$$

where $YTIPS(t)$ is the percentage TIPS yield at time t.

Figure 7 shows how the current government bond yield (the "Bond Yield" line) minus expected inflation ("Estimated Inflation") leads to an estimate of the real bond return and hence the long-term expected real bond return ("Estimated Real Bond Yield"), which is the estimate through March of 1998 and the TIPS yield thereafter.[29] From the Equation 5 (or, more recently, Equation 6) formulation, expected real bond returns averaged 3.7 percent over the full period, a very respectable real yield, given the limited risk of government bonds, and good recompense for an investor's willingness to bear some bond-price volatility. Investors may not always have viewed government debt as the rock-solid investment, however, that it is generally considered today.

The 3.7 percent real bond return consists of an average nominal bond yield of 4.9 percent minus an expected inflation rate of 1.2 percent. For comparison, the average actual inflation rate has been 1.4 percent. In the years after World War II, the rate of peacetime inflation embedded in investors' memory banks was essentially zero, perhaps even slightly negative. Consequently, bond investors kept expecting inflation to go away, despite its persistence at a modest rate in the 1950s and early 1960s and an accelerating rate thereafter. As a result, bonds were badly priced for reality during most of

Figure 6. Estimating Future Inflation, 1810–2001

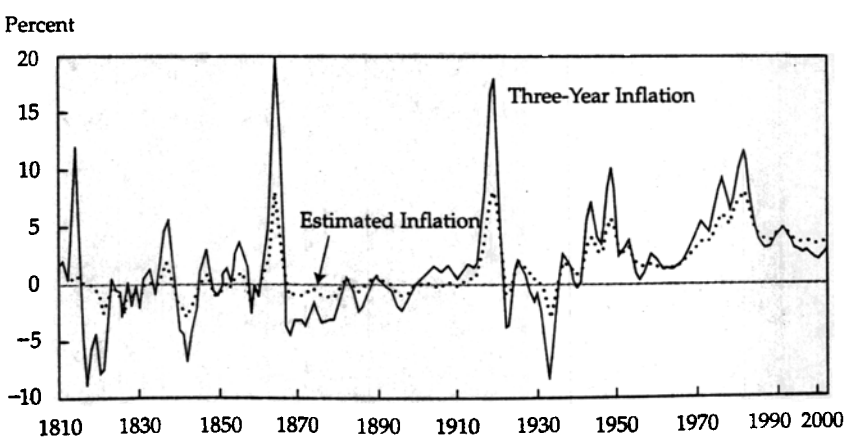

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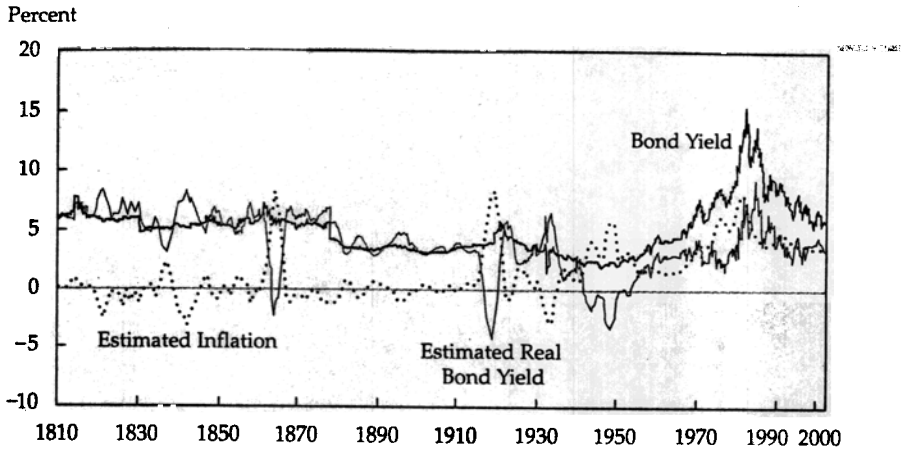
Figure 7. Estimating Real Bond Yields, 1810–2001



these two decades; they turned out to be certificates of confiscation for their holders until people finally woke up in the 1970s and 1980s. Actual inflation exceeded expected inflation with few exceptions from the start of World War II until roughly 1982; as can be seen in Figure 7, our model captures this phenomenon. Expectations are lower than actual outcomes during this span.

Figure 7 also shows several regimes of real yield with distinct structural change from one regime to the next. From the time the United States was in its infancy until the end of Reconstruction in the late 1870s, investors would not have viewed U.S. government bonds as a secure investment. They would have priced these bonds to deliver a 5–7 percent real yield, except during times of war. The overall stability of the yields is impressive: Unlike the history of stock prices, the surprise elements have been small.

Once the United States had survived the Civil War and the security of U.S. government debt had been demonstrated repeatedly, investors began to price government debt at a 3–5 percent real yield. As Figure 7 shows, this level held, with a brief interruption in World War I, until the country went off the gold standard in 1933. This record is remarkable in view of the high rate of economic growth, but revolutionary technological change in those days, especially in transportation and agriculture, led to such stunning reductions in product costs that inflation was kept at bay except for very brief intervals.

For the next 20–25 years, the nation struggled with the Great Depression, World War II, and the war's aftermath. Investors slowly began to realize that deflationary price drops did not rebound fully after the trough of the Depression and that inflationary price increases did not retreat after the end of the war. The changed role of government plus the end of the gold standard had altered the picture, perhaps irrevocably. During this span, investors priced bonds to offer a 2–4 percent *notional* yield but a rocky –3 percent to +3 percent real yield. As Figure 7 shows, bond investors woke up late to the fact that inflation was now a normal part of life.

From the mid-1950s to date, investors have struggled with more structural inflation and more inflation uncertainty than ever before. Although investors sought to price bonds to deliver a real yield, inflation consistently exceeded their expectations. Only during the down cycle of the inflation roller coaster of 1980–1985 did bonds finally provide real yields to their owners. After this experience, bond investors developed an anxiety about inflation far greater than objective evidence would support. The result was a brief spike in real bond returns in 1984, as Figure 7 shows, with bond yields still hovering at 13.8 percent, even though three-year inflation had fallen to 4.7 percent (and our regression model for future inflation would have suggested expected inflation of 4.6 percent). The "expected" real yield was a most unusual 9.2 percent because investors were not yet prepared to believe that double-digit inflation was a thing of the past.

Another interesting fact is evident in Figure 8: The expected real bond returns produced by our formulation are highly correlated with the actual real returns earned over the subsequent decade. For 1810 to 1991, the expected real bond return has a 0.52 correlation with the actual real bond return earned over the next 10 years; from 1945 to date, the correlation rises to an impressive 0.63. Panel A of **Table 2** shows that the coefficient is reliably positive but not reliably more than 1.00, which suggests that, unlike expected real stock returns, no powerful tendency for reversion to the mean is at work in real bond yields. When we used the 19 available nonoverlapping samples (Panel B), we found the resulting correlation to be 0.64, which is a statistically significant relationship.[30]

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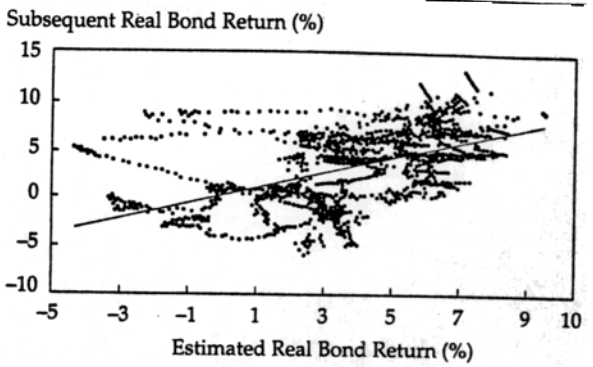
Figure 8. Estimated and Subsequent Actual Real Bond Yield, 1802–2001



Why is the bond model a better predictor, when raw data are used, than the stock model for the two-century history? Two reasons seem evident. First, stocks have been more volatile than bonds for almost all 200 years of U.S. data. Therefore, any model for expected real stock returns should have a larger error term. Second, stocks are by their very nature longer term than bonds: A 10-year bond expires in 10 years; stocks have no maturity date.

The bond market correlations would be even better were it not for the negative real yields during times of war, when people tend to consider the inflation a temporary phenomenon. These episodes show up as the "loops" to the left of the body of the scatterplot in Figure 8. At these times, many U.S. investors apparently subordinated their own interests in a strong real yield to the needs of the nation: Long Treasury rates were essentially pegged during World War II and up to 1951, but that did not stop investors from buying them.

Step IV: Estimating the Equity Risk Premium. If we now take the difference between the expected real stock return and the expected real bond return, we are left with the expected equity risk premium:

$$ERP(t) = ERSR(t) - ERBR(t), \quad (7)$$

where $ERSR(t)$ is the expected real stock return starting at time t and $ERBR(t)$ is the expected real bond return starting at time t.

Figure 9 shows the results of this simple framework for estimating the risk premium over the past 192 years. Many observers may be startled to see that this estimate of the forward-looking risk premium for stocks has rarely been above 5 percent in the past 200 years; the exceptions are war, its aftermath, and the Great Depression. The historical average risk premium is a modest 2.4 percent, albeit with a rather wide range. The wide range is more a result of the volatility of expected real bond returns than the volatility of expected real stock returns, which are surprisingly steady except in times of crisis.[31]

Over the past 192 years, our model (Equation 3) suggests that an objective evaluation would have pegged expected real stock returns at about 6.1 percent on average, only 120 bps higher than the average dividend yield. Investors have earned fully 70 bps more than this objective expectation, but they did not have objective reasons to expect to earn as much as they did. Our model suggests that an objective evaluation would have pegged expected real bond returns at about 3.7 percent. Investors have earned 20 bps less because of the inflationary shocks of the 1960s to 1980s; they expected more than they got.

The difference between the expected real returns for stocks and bonds reveals a stark reality. An objective estimate of the expected risk premium would have averaged 2.4 percent (240 bps) during this history (6.1 percent expected real stock returns minus 3.7 percent expected real bond returns), not the oft-cited 5 percent realized excess return that

Table 2. Regression Results: Estimated Real Bond Return versus Actual 10-Year Real Bond Return
(*t*-statistics in parentheses)

Period		b	R^2	Correlation	Serial Correlation
A. Raw data: RBR(t) = a + b[ERBR(t – 120)]					
1810–2001	0.45%	0.81%	0.266	0.52	0.999
	(3.5)	(28.1)			0.997
1945–2001	–0.74	1.05	0.399	0.63	0.997
	(–4.0)	(19.3)			0.980
B. Using 19 nonoverlapping samples, beginning December 1810					
1810–2001	–1.81%	1.31%	0.4120	0.64	0.182
	(–1.1)	(3.5)			0.677

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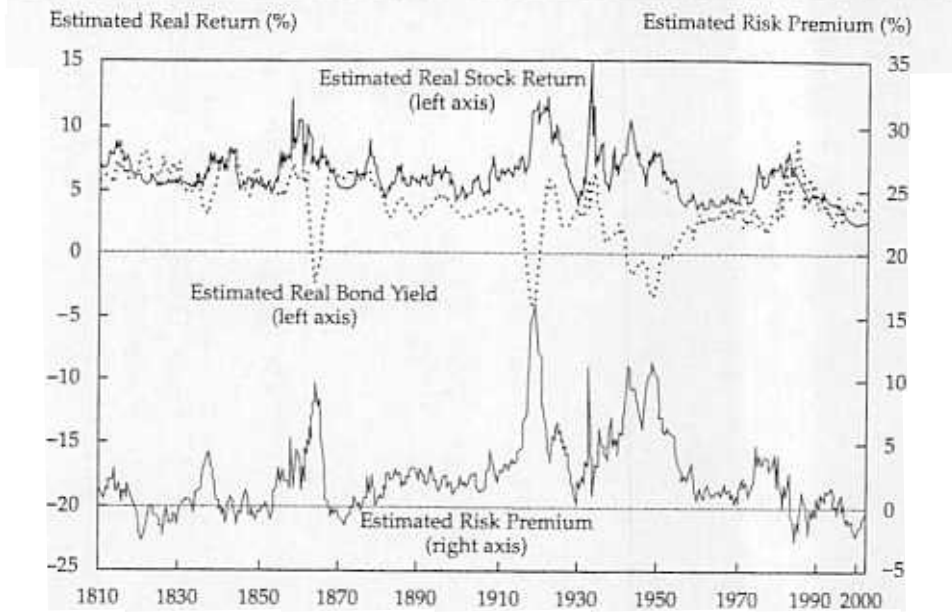
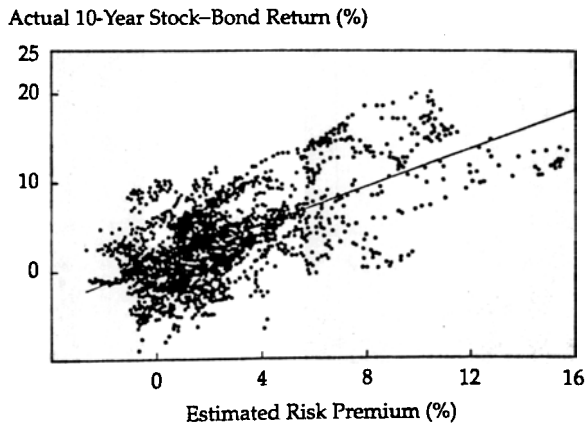
Figure 9. Estimating the Equity Risk Premium, 1810–2001



much of the investment world now depends on. Investors have *earned* a higher 3.3 percent (330 bps) excess return for stocks (6.8 percent actual real stock returns minus 3.5 percent for bonds), but the reason is the array of happy accidents for stocks and one extended unhappy accident for bonds.

All of this analysis is of mere academic interest, however, unless we can establish a link between our estimated risk premium and actual subsequent relative returns. Indeed, such a link does exist. The result of our formulation for the equity risk premium has a 0.79 correlation with the actual 10-year excess return for stocks over bonds since 1945 and a 0.66 correlation for the full span. This strong link is clear in **Figure 10**, for 1810–2001, and **Table 3** (where, for convenience, we have defined the 10-year excess return of stocks relative to bonds as *ERSB*); each 100 bp change in the equity risk premium is worth modestly more than 100 bps in subsequent annual excess returns for stocks relative to bonds over the next 10 years. As with the expected stock return model (Equation 3), the link for 20-year results is stronger, with correlations over the full span and since 1945 of, respectively, 0.64 and 0.95.

Figure 10. Risk Premium and Subsequent 10-Year Excess Stock Returns: Correlations, 1810–1991



This strong link between objective measures of the risk premium and subsequent stock–bond excess returns is also clear for the 1945–2001 period shown in **Figure 11**, in which every wiggle of our estimate for the risk premium is matched by a similar wiggle in the subsequent 10-year excess return that stockholders earned relative to bondholders. Figure 11 shows that the excess returns on stocks relative to bonds became negative in the late 1960s on a 10-year basis, following low points in the risk premium, and again touched zero 10 years after the 1981 peak in bond yields.

We can also see in Figure 11 how the gap in 10-year results opened up sharply for the 10 years of the 1990s; it opened to unprecedented levels, even wider than in the early 1960s. Prior to this gap opening, the fit between the risk premium and subsequent excess returns is remarkably tight. The question is whether this anomaly is sustainable or is destined to be "corrected." History suggests that such anomalies are typically corrected, especially when the theoretical case to support them is so weak. This reminder should be sobering to investors who are depending on a large equity risk premium.

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Table 3. Regression Results: Estimated Equity Risk Premium versus Actual 10-Year Excess Return of Stocks versus Bonds
(*t*-statistics in parentheses)

Period	*a*	*b*	R^2	Correlation	Serial Correlation
A. Raw data: ERSB(t) = a + b[ERP(t – 120)]					
1810–2001	0.91%	1.08%	0.430	0.66	0.993
	(8.8)	(40.6)			0.995
1945–2001	2.85	1.41	0.621	0.79	0.995
	(15.4)	(30.4)			0.996
B. Using 19 nonoverlapping samples, beginning December 1810					
1810–2001	0.84%	1.36%	0.490	0.70	0.055
	(0.8)	(4.0)			0.371

As with the models for real stock returns and for real bond returns, we also used nonoverlapping spans to take out the effect of the strong serial correlation in the estimated risk premium. For the 19 nonoverlapping spans (Panel B of Table 3), the correlation for the full period jumps to 0.70, with a highly significant *t*-statistic of 4.0.[32]

Conclusions

We have advanced several provocative assertions.

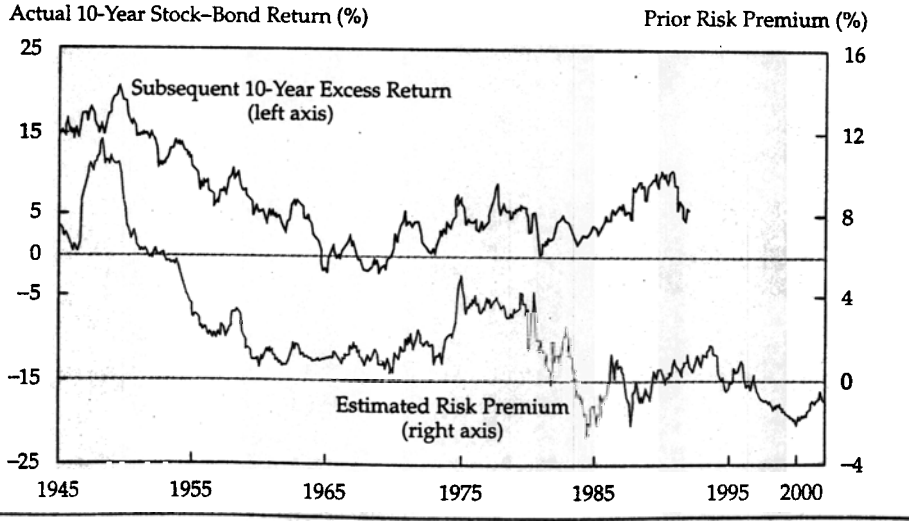
- The observed real stock returns and the excess return for stocks relative to bonds in the past 75 years have been extraordinary, largely as a result of important nonrecurring developments.
- It is dangerous to shape future expectations based on extrapolating these lofty historical returns. In so doing, an investor is tacitly assuming that valuation levels that have doubled, tripled, and quadrupled relative to underlying earnings and dividends can be expected to do so again.

The investors of 75 years ago would not have had an objective basis for expecting the 8 percent real returns or 5 percent risk premium that stocks subsequently delivered. The estimated equity risk premium at the time was above average, however, which makes 1926 a better-than-average starting point for the historical risk premium.

The real internal growth that companies generated in their dividends averaged 0.9 percent a year over the past 200 years, whereas earnings growth averaged 1.4 percent a year over the past 131 years.

Dividends and earnings growth was slower than the increase in real per capita GDP, which averaged 1.6 percent over the past 200 years and 2.0 percent over the past 131 years. This internal growth is far less than the consensus expectations for future earnings and dividend growth.

Figure 11. Risk Premium and Subsequent 10-Year Excess Returns, 1945–2001



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- The historical average equity risk premium, measured relative to 10-year government bonds as the risk premium investors might objectively have expected on their equity investments, is about 2.4 percent, half what most investors believe.
- The "normal" risk premium might well be a notch lower than 2.4 percent because the 2.4 percent objective expectation preceded *actual* excess returns for stocks relative to bonds that were nearly 100 bps higher, at 3.3 percent a year.
- The current risk premium is approximately zero, and a sensible expectation for the future real return for both stocks and bonds is 2–4 percent, far lower than the actuarial assumptions on which most investors are basing their planning and spending.[33]
- On the hopeful side, because the "normal" level of the risk premium is modest (2.4 percent or quite possibly less), current market valuations need not return to levels that can deliver the 5 percent risk premium (excess return) that the Ibbotson data would suggest. If reversion to the mean occurs, then to restore a 2 percent risk premium, the difference between 2 percent and zero still requires a near halving of stock valuations or a 2 percent drop in real bond yields (or some combination of the two). Either scenario is a less daunting picture than would be required to facilitate a reversion to a 5 percent risk premium.
- Another possibility is that the modest difference between a 2.4 percent normal risk premium and the negative risk premiums that have prevailed in recent quarters permitted the recent bubble. Reversion to the mean might not ever happen, in which case, we should see stocks sputter along delivering bondlike returns, but at a higher risk than bonds, for a long time to come.

The consensus that a normal risk premium is about 5 percent was shaped by deeply rooted naiveté in the investment community, where most participants have a career span reaching no farther back than the monumental 25-year bull market of 1975–1999. This kind of mind-set is a mirror image of the attitudes of the chronically bearish veterans of the 1930s. Today, investors are loathe to recall that the real total returns on stocks were negative for most 10-year spans during the two decades from 1963 to 1983 or that the excess return of stocks relative to long bonds was negative as recently as the 10 years ended August 1993.[34]

When reminded of such experiences, today's investors tend to retreat behind the mantra "things will be different this time." No one can kneel before the notion of the long run and at the same time deny that such circumstances will occur in the decades ahead. Indeed, such crises are more likely than most of us would like to believe. Investors greedy enough or naive enough to expect a 5 percent risk premium and to substantially overweight equities accordingly may well be doomed to deep disappointments in the future as the realized risk premium falls far below this inflated expectation.

What if we are wrong about today's low equity risk premium? Maybe real yields on bonds are lower than they seem. This chance is a frail reed to rely on for support. At this writing, at the end of 2001, an investor can buy TIPS, which provide government-guaranteed yields of about 3.4 percent, but inflation-indexed bond yields are a relatively recent phenomenon in the United States. So, we could not estimate historical real yields for prior years directly, only through a model such as the one described here. If we compare our model for real stock returns, at 2.4 percent in mid-2001, with a TIPS yield of 3.4 percent, we get an estimate for the equity risk premium of –100 bps.

Perhaps real earnings and dividend growth will exceed economic growth in the years ahead, or perhaps economic growth will sharply exceed the historical 1.6 percent real per capita GDP growth rate. These scenarios are certainly possible, but they represent the dreams of the "new paradigm" advocates. The scenarios are unlikely. Even if they prove correct, it will likely be in the context of unprecedented entrepreneurial capitalism, unprecedented new enterprise creation, and hence, unprecedented dilution of shareholders in existing enterprises.

The recurring pattern of history is that exceptionally poor or exceptionally rapid economic growth is never sustained for long. The best performance that dividend growth has ever managed, relative to real per capita GDP, is a scant 10 bp outperformance. This rate, the best 40-year real dividend growth *ever seen*, fell far short of real GDP growth: Real dividend growth was some 2 percent a year below real GDP growth during those same 40-year spans. So, history does not support those who hope that dividend growth will exceed GDP growth. This evidence is not encouraging for those who wish to see a 1.4 percent dividend yield somehow transformed into a 5 percent (or higher) real stock return.

The negative risk premium that precipitated the writing of "The Death of the Risk Premium" (Arnott and Ryan) in early 2000 was not without precedent, although most of the precedents, until recently, are found in the 19th century. In 1984 and again just before the 1987 market crash, real bond yields rose materially above the estimated real return on stocks. How well did this development

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predict subsequent relative returns? Stated more provocatively, why didn't our model work? Why didn't bonds beat stocks in the past decade? After all, with the 1984 peak in real bond returns and again shortly before the 1987 crash, the risk premium dipped even lower than the levels seen at the market peak in early 2000. Yet, stocks subsequently outpaced bonds. For an answer, recall that the context was a more than doubling of stock valuations, whether measured in price-to-book ratios, price-to-dividend ratios, or P/E multiples. If valuation multiples had held constant, the bonds would have prevailed.[35]

Appendix A. Estimating the Constituents of Return

An analysis of historical data is only as good as the data themselves. Accordingly, we availed ourselves of multiple data sources whenever possible. We were encouraged by the fact that the discrepancies between the various sources led to compounded rates of return that were no more than 0.2 percent different from one another.

Long Government Bond Yields, *BY(t)*. Our data sources are as follows: for January 1800 to May 2001, 10-year government bond yields from Global Financial Data of the National Bureau of Economic Research (NBER) (data were annual until 1843 and were interpolated for monthly estimates); for June 2001 to December 2001, Bloomberg; and for January 1926 to December 2000, Ibbotson Associates, long-term government bond yields and returns. In cases of differences, we (1) averaged the yield data and (2) recomputed monthly total returns based on an assumed 10-year maturity standard.

Inflation, *INF(t)*. We used two sources of inflation and U.S. Consumer Price Index data. For January 1801 to May 2001, NBER (annual until 1950; interpolated for monthly estimates); for June 2001 to December 2001, Bloomberg; and for January 1926 to December 2000, Ibbotson Associates. In cases of differences, we averaged the available data. Ibbotson data were given primary (two-thirds) weighting for 1926–1950 because the NBER data are annual through 1950.

Gross Domestic Product, *GDP(t)*. For January 1800 to September 2001, NBER GNP data annually through 1920, interpolated July-to-July; for 1921–2001, quarterly GDP data; and for December 2001, *Wall Street Journal* consensus estimates.

Dividend Yield in Month *t*, *DY(t)*, and Return on Stocks in Month *t*, *RS(t)*. For January 1802 to December 1925, G. William Schwert (1990); for February 1871 to March 2001, Robert Shiller (2000); for January 1926 to December 2000, Ibbotson Associates (2001); and for April 2001 to December 2001, Bloomberg. In cases of differences, we averaged the available data. In Shiller's data, monthly dividend and earnings data are computed from the S&P four-quarter data for the quarter since 1926, with linear interpolation to monthly figures. Dividend and earnings data before 1926 are from Cowles (1939), interpolated from annual data.

Notes

1. The "bible" for the return assumptions that drive our industry is the work of Ibbotson Associates, building on the pioneering work of Ibbotson and Sinquefield (1976a, 1976b). The most recent update of the annual Ibbotson Associates data (2001) shows returns for U.S. stocks, bonds, bills, and inflation of, respectively, 11.0 percent, 5.3 percent, 3.8 percent, and 3.1 percent. These figures imply a real return for stocks of 7.9 percent and a risk premium over bonds of 5.7 percent (570 bps), both measured over a 75-year span. These data shape the expectations of the actuarial community, much of the consulting community, and many fund sponsors.
2. Fischer Black was fond of pointing out that examining the same history again and again with one new year added each passing year is an insidious form of data mining (see, for example, Black 1976). The past looks best when nonrecurring developments and valuation-level changes have distorted the results; extrapolating the past tacitly implies a belief that these nonrecurring developments can recur and that the changes in valuation levels will continue.
3. We strongly suggest that the investment community draw a distinction between past excess returns (observed returns from the past) and expected risk premiums (expected return differences in the future) to avoid continued confusion and to reduce the dangerous temptation to merely extrapolate past excess returns in shaping expectations for the risk premium. This habit is an important source of confusion that, quite literally, (mis)shapes decisions about the management of trillions in assets worldwide. We propose that the investment community begin applying the label "risk premium" *only* to expected future return differences and apply the label "excess returns" to observed historical return differences.
4. To see the effect of compounding at this rate, consider that if our ancestors could have earned a mere 1.6 percent real return on a $1 investment from the birth of Christ in roughly 4 B.C. to today, we would today have enough to buy more than the entire world economy. Similarly, the island of Manhattan was ostensibly purchased for $24 of goods, approximately the same as an ounce of gold when the dollar was first issued. This modest sum invested to earn a mere 5 percent real return would have grown to more than $20 billion in the 370 years since the transaction. At an 8 percent real return, as stocks earned from 1926 to 2000 in the Ibbotson data, this $24 investment would now suffice to buy more than the entire world economy.

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5. No rational investor buys if he or she expects less than 1 percent real growth a year in capital, but objective analysis will demonstrate that this return is what stocks have actually delivered, plus their dividend yield, plus or minus any profits or losses from changes in yields. As Asness pointed out in "Bubble Logic" (2000), few buyers of Cisco would have *expected* a 1 percent internal rate of return at the peak, although the stock was priced to deliver just that, even if the overly optimistic consensus earnings and growth forecasts at the time were used. These buyers were focused on the view that the stock would produce handsome gains, as it had in the past, rather than on pursuing an objective evaluation, by using IRR or similar objective valuation tools, of expected returns. Such a focus plants the seeds of major disappointment.
6. The Welch study investigated an expected *arithmetic* risk premium for stocks relative to *cash*, not bonds. The difference between arithmetic and geometric returns is often illustrated by someone earning 50 percent in one year and −50 percent in the next. The arithmetic average is zero, but the person is down 25 percent (or 13.4 percent a year). Most practitioners think in terms of compounded geometric returns; in this example, practitioners would focus on the 13 percent a year loss, not on the zero arithmetic mean. If stocks have 16 percent average annual volatility (the average since World War II), the result is that the arithmetic mean is 130 bps higher than the geometric mean return (the difference is approximately half the variance, or 16 percent × 16 percent/2). Such a difference might be considered a "penalty for risk." If we add a 70 bp real cash yield (the historical average) plus a 720 bp risk premium minus a 130 bp penalty for risk, we find 6.6 percent to be the implied consensus of the economists for the geometric real stock return.
7. Such a return could easily fall to 0–2 percent net of taxes, especially in light of government's taxes on the inflation component of returns.
8. Smith's work even won a favorable review from John Maynard Keynes (for Keynes' approach, see his 1936 classic).
9. TIPS is the acronym for Treasury Inflation-Protected Securities, which have been replaced by Treasury Inflation-Indexed Securities.
10. In fairness, growth is now an explicit part of the picture. Dividend payout ratios are substantially lower than in the early 1920s and the 19th century as a result, at least in part, of corporate desires to finance growth. That said, our own evidence would suggest that internal reinvestment is not necessarily successful: High payout ratios precede higher growth than do low payout ratios.
11. We are indebted to G. William Schwert and Jeremy Siegel for some of the raw data for this analysis (see also Schwert 1990 and Siegel 1998). Although multiple sources exist for data after 1926 and a handful of sources provide data beginning in 1855 or 1870, Professor Schwert was very helpful in assembling these difficult early data. Professor Siegel provided earnings data back to 1870. We have not found a source for earnings data before 1870.
12. The U.S. Bureau of Labor Statistics maintains GDP data from 1921 to date; the earlier data are for GNP (gross national product). Because the two were essentially the same thing until international commerce became the substantial share of the economy that it is today, we used the GNP data from the Bureau of Labor Statistics for the 19th century and the first 20 years of the 20th century.
13. We stripped out reinvestment in the measure of real dividend growth shown in Figure 3 because investors are already receiving the dividend. To include dividends in the real dividend growth would double-count these dividends. What should be of interest to us is the internal growth in dividends stemming from reinvestment of the retained earnings.
14. We multiplied the real dividends by 10 to bring the line visually closer to the others; the result is that on those few occasions when the price line and dividend line touch, the dividend yield is 10 percent.
15. The fact that growth in real dividends and earnings is closer to per capita GDP growth than it is to overall GDP growth is intuitively appealing on one fundamental basis: Real per capita GDP growth measures the growth in productivity. It is sensible to expect real income, real per share earnings, and real per share dividends to grow with productivity rather than to mirror overall GDP growth.
16. This history holds a cautionary tale with regard to today's stock option practices.
17. This fall in dividends of existing enterprises is not surprising when one considers that the companies that existed in 1802 probably encompass, at most, 1 percent of the economy of 2001. The world has so changed that, at least from the perspective of the dominant stocks, today's economy would be unrecognizable in 1802.
18. Another way to think about this idea is to recognize the distinction between a market portfolio and a market index. The market portfolio shows earnings and dividend growth that are wholly consistent with growth in the overall economy (Bernstein 2001a). But if one were to unitize that market portfolio, the unit values would not grow as fast as the total capitalization and the earnings and dividends per unit (per "share" of the index) would not keep pace with the growth in the aggregate dollar earnings and dividends of the companies that compose the market portfolio. (When one stock is dropped and another added to a market index, typically the added stock is larger in capitalization than the deletion, which increases the divisor for constructing the index.) Precisely the same thing would happen in the management of an actual index fund. When a stock was replaced, the proceeds from the deleted stock would rarely suffice to fund the purchase of the added stock. So, all stocks would be trimmed slightly to fund that purchase; this consequence is implied by the change in the divisor for an index. It is this mechanism that drives the difference between the growth of the aggregate dollar earnings and dividends for the market portfolio, which will keep pace with GDP growth over time, and the growth of the "per share" earnings and dividends for the market *index* that creates the dilution we attribute to entrepreneurial capitalism. After all, entrepreneurial capitalism creates the companies that we must add to the market portfolio, thus changing our divisor and driving a wedge between the growth in market earnings or dividends and the growth in earnings and dividends per share in a market index.
19. See Bernstein (2001b). Over the past 131 years, the correlation between payout ratios and subsequent 10-year growth in real earnings has been 0.39; over the past 50 years, this correlation has soared to 0.66. Apparently, the larger the fraction of earnings paid out as dividends, the faster earnings subsequently grow, which is directly contrary to the Miller–Modigliani maxim (see Miller and Modigliani 1961 and Modigliani and Miller 1958).
20. To produce a 3.4 percent real return from stocks, matching the yield on TIPS, real growth in dividends needs to be 1.9 percent (twice the long-term historical real growth rate) while valuation levels remain where they are. Less than twice the historical growth in real dividends, or a return to the 3–6 percent yields of the past, will not get us there.
21. We have made the simplifying assumption that "long term" is a 10-year horizon. Redefining the long-term returns over a 5-year or 20-year horizon produces similar results.
22. Because this adjusted dividend is always at or above the true dividend, we have introduced a positive error into the average dividend yield. We offset this error by subtracting the 40-year average difference between the adjusted dividend and the true dividend. In this way, $EDY(t)$ is not overstated, on average, over time.

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23. Of course, stock buybacks increase the share of the economy held by existing shareholders.
24. Arnott and Asness (2002) have shown that since 1945, the payout ratio has had a 77 percent correlation with subsequent real earnings growth. That is, higher retained earnings have historically led to slower, not faster, earnings growth.
25. Throughout this article, when we refer to a 10-year average or a 40-year average, we have used the available data if fewer years of data were available. For instance, for 1820, we used the 20-year GDP growth rate because 40 years of data were unavailable. We followed a convention of requiring at least 25 percent of the intended data; so, if the analysis was based on a 40-year average, we tolerated a 10-year average if necessary. To do otherwise would have forced us to begin our analysis in about 1840 and lose decades of interesting results. Because data before 1800 are very shaky and we required at least 10 years of data, our analysis begins, for the most part, in 1810.
26. We cannot know the 10-year returns from starting dates after 1991, so 192 years of expected return data lead to 182 years of correlation with subsequent 10-year actual returns.
27. Another way to deal with serially correlated data is to test correlations of differenced data. When we carried out such tests, we found that over the full span, the R^2 actually *rose* to 0.446 from the 0.214 shown in Panel A of Table 1; moreover, since 1945, the differenced results showed a still impressive 46 percent correlation. These results are available from the authors on request.
28. In an *ex ante* regression, the model is respecified for each monthly forecast with the use of all previously available data only.
29. We made the simplifying assumption that "long term" is a 10-year horizon. Redefining the long-term returns over a 5-year or 20-year horizon produced similar results.
30. Even when we considered successive differences to eliminate the huge serial correlation of real bond yields and 10-year real bond returns, the result from 1945 to date (available from the authors) was identical to the result for the raw data—a correlation of 0.63.
31. For investors accustomed to the notion that stock returns are uncertain and bond returns are assured over the life of the bond, this result will come as a surprise. But conventional bonds do *not* assure real returns; their expected real returns, therefore, should be highly uncertain. Stocks do, in a fashion, pass inflation through to the shareholder. So, nominal returns for stocks may be volatile and uncertain, but expected real stock returns are much more tightly defined than expected real bond returns.
32. Differencing caused the correlation for the full 182-year span to fall from 0.66 to 0.61 and, for the span following World War II, caused it to fall from 0.79 to 0.48.
33. For the taxable investor, the picture is worse, of course. In the United States, investors are even taxed on the inflation component of returns. From valuation levels that are well above historical norms, a negative real after-tax return is not at all improbable.
34. The excess return of stocks over bonds was negative also in the decades ended September 1991, November 1990, most 10-year spans ending August 1977 to June 1979, and the spans ending September 1974 to January 1975.
35. Consider the 10 years starting just before the stock market crash in September 1987. This span began with double-digit bond yields. The bond yield of 9.8 percent minus a regression-based inflation expectation of 3.6 percent led to an expected real bond return of 6.2 percent. The stock yield of 2.9 percent plus expected real per capita GDP growth of 1.6 percent minus an expected dividend shortfall relative to per capita GDP of 0.4 percent led to an expected real stock return of 4.0 percent. The risk premium was –2.0 percent. But stocks beat bonds by 4.9 percent a year over the next 10 years ending September 1997. What happened? The dividend yield plunged to 1.7 percent. This plunge in yields contributed 5.8 percent a year to stock returns; in the absence of this revaluation, stocks would have underperformed bonds by –0.9 percent. So, the –2.0 percent forecast was not bad; dividends rose a notch faster than normal, and more importantly, the price that the market was willing to pay for each dollar of dividends nearly doubled.

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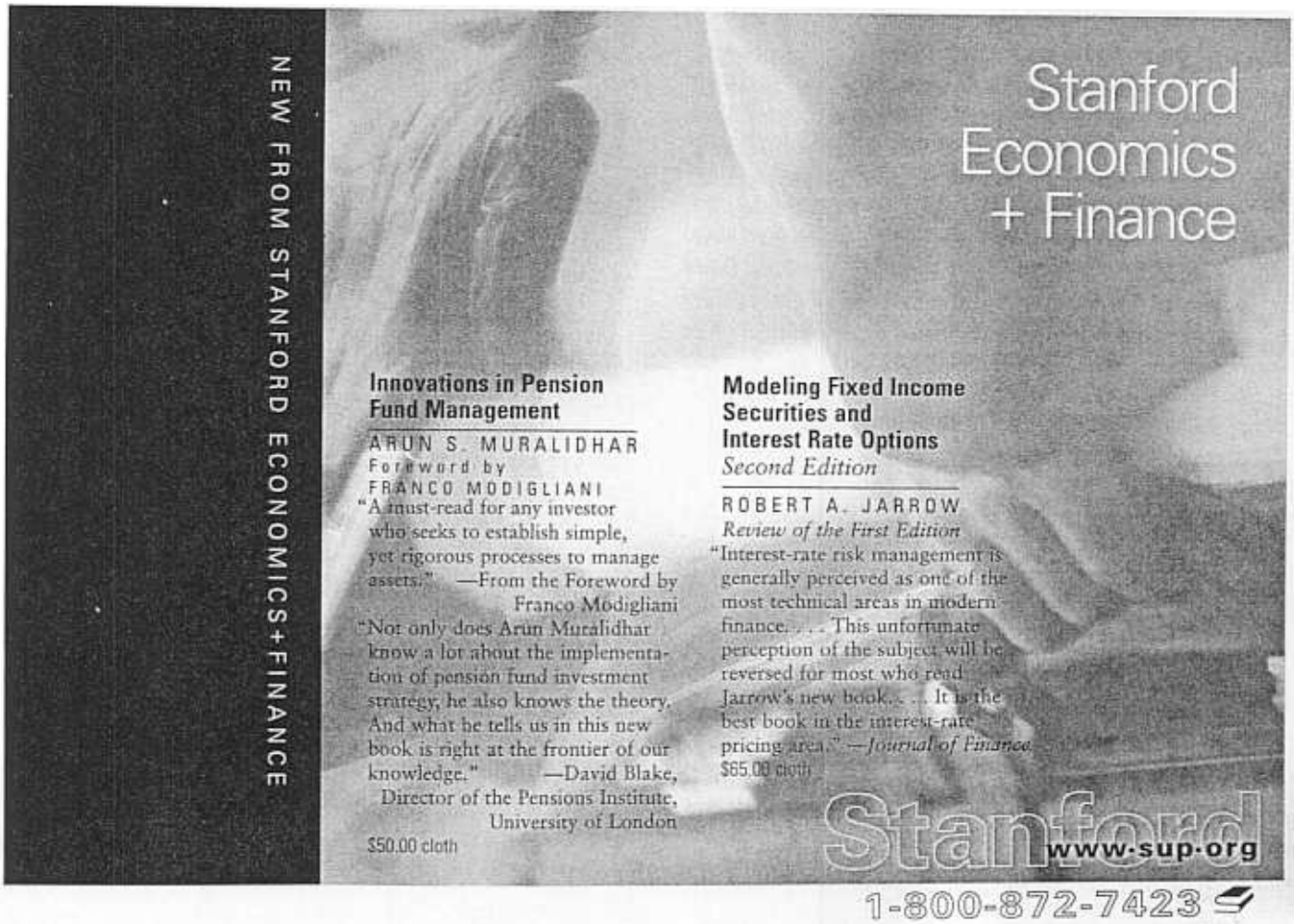

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The Death of the Risk Premium

Consequences of the 1990s.

Robert D. Arnott and Ronald J. Ryan

A pension fund's objective is 1) to pay or fund the pension liability, 2) at the lowest cost to the plan sponsor, 3) subject to sensible risk. This means that, ideally, returns on the pension assets should be the primary source to fund these liabilities, rather than a pension contribution coming from the employer, the employees, or, in the case of public funds, current or future taxpayers. For university endowments, the same logic applies, typically over an even longer span than most pension portfolios.

One of the most striking developments of the 1990s is the evaporation of the forward-looking risk premium for stocks measured relative to bonds. This development is new enough that it is not yet widely accepted as fact. Whether it is fact or mere hypothesis, it is useful to consider the implications of a negative risk premium for stocks, which are far-reaching and sobering. They affect funding policy, investment return expectations, corporate earnings, and asset allocation planning, not to mention lesser aspects of institutional asset management.

WHAT IF EQUITIES DON'T BEAT BONDS LONG-TERM?

If long-term sustainable future returns for a balanced portfolio are only around 6%, how well funded is your pension fund? What are the policy allocation implications if equities don't beat bonds over the next 10 or 20 years? These are questions we need to ask in the wake of today's record valuation levels and relatively high real yields for

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government bonds. Yet they are not being explored in any meaningful way.

This may seem an alarmist perspective, since stocks have always been priced to offer a material risk premium to bonds. During the lifetime of each and every one of us, this has been self-evident. And investors have enjoyed this risk premium; stocks have outpaced bonds by about 5% per year for a 74-year span, and have produced real returns north of 7% for an entire century.

Indeed, a good case can be made for the notion that the party is not over. Dividends have been replaced with stock buy-backs, mergers and acquisition activity, and ordinary reinvestment to fund future growth. Furthermore, as even a casual market observer could easily see, the technology revolution is real, delivering faster economic growth and more wealth creation than we have ever seen so late in an economic expansion. The key question here is how much of this good news is already reflected in market prices.

Is the party over? It would be foolish to say that markets can go no higher. Of course they can go higher—but there is a trade-off. The higher the markets go, without underlying fundamentals keeping pace, the lower the *future* rates of return must fall. This is a simple truism that has some rather alarming implications. Few would reject the notion that future real returns on stocks cannot, from current market levels, match the past. Interestingly, we *can* put a number on it.

One path to estimating future returns is to examine the past. Over the past 74 years, stocks have produced a real return of 8.4% a year. Now, let's dissect this 8.4% real return to see what it tells us about future equity potential.

Real Returns

We know that 2 percentage points of the 8.4% real return have come as a direct consequence of dividend yields at their lowest levels in U.S. history and P/E multiples now at their highest levels in modern U.S. history. Only the Great Depression saw higher P/E multiples, but these were based on severely depressed earnings, where today's multiples are based on near-peak profit margins.

In 1925, investors paid 18 years' worth of current dividends to buy stocks; today's investors willingly pay 80 years' worth of current dividends to buy stocks, more than quadruple the 1925 levels. Investors are now willing to pay three times the Price/Earnings ratio that they paid in 1925.

This trend would be dangerous to extrapolate: Will dividend yields fall fourfold to 0.3% in the next 75 years, as P/E ratios triple again to north of 100? While this is not impossible, nor is a return to historical norms (or worse), which would lead to truly dreadful real returns in the years ahead. Accordingly, the 2 percentage points of the historical real return that are attributable to market revaluation cannot be extrapolated into the future. Absent this revaluation of the price investors will pay for a dollar of dividends, real returns would have been 2 percentage points lower, or 6.4%.

The advocates of regression to the mean would argue that this part of the real return, which has contributed 2 percentage points of the 8.4% earned in the past 74 years, is far more likely to be negative in the years ahead than positive. The new paradigm crowd would argue that valuation levels can and should go far higher still. The naive efficient markets view would suggest that current pricing is fair, and therefore that the best estimate for this part of the real return is zero. As we will see, even the efficient markets view, that current valuation levels are fair and sustainable, probably leads to a negative risk premium in the years ahead.

Dividend Yields

Today's stock market dividend yield of around 1.2% is 4.2 percentage points below the dividend yield of 1925. To be sure, part of the reason for today's low yields is that dividends have been supplanted, in part, by stock buy-backs, reinvestment to improve future growth, and merger and acquisition activity. But, it is just as appropriate to view these reinvestments on behalf of the shareholder as sources of faster real dividend growth, rather than as "hidden dividends" per se. Accordingly, this drop in dividend yields represents a 4.2 percentage point reduction in prospective real equity returns, partly offset by faster growth.

Suppose we take the 8.4% real return of the past 74 years, and subtract both the 2 percentage points that is attributable to rising valuation levels and the 4.2 percentage point drop in forward-looking dividend yields on the S&P 500. This brings us down to an expected real return for equities of 2.2%, a shockingly bad real return.

Real Dividend Growth

Real dividend or earnings growth cannot exceed real economic growth in the very long run, or eventually earnings and dividends grow larger than the economy itself. Furthermore, since a material part of economic growth is derived from new enterprises that are

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EXHIBIT 1
HOW LONG IS LONG-TERM?
REVISITING THE IBBOTSON DATA

	74 Years Since Dec. 1925	Outlook Starting Jan. 2000
Starting Dividend Yield	5.4%	1.2%
Growth in Real Dividends	1.0%	2.0% (approx.)
Change in Valuation Levels[a]	2.0%	Unknown
Cumulative Real Return	8.4%	3.2% (approx.)
Less Starting Bond Real Yield	3.7%[b]	4.1%[c]
Less Bond Valuation Change[d]	–0.4%	Unknown
Cumulative Risk Premium	5.1%	-0.9% (approx.)

[a]Yields went from 5.4% to 1.2%, representing a 2.1% annual increase in the Price/Dividend Valuation Level.

[b]A 3.7% yield, less an assumed 1926 inflation expectation of zero.

[c]The yield on U.S. government inflation-indexed bonds.

[d]Bond yields went from 3.7% to 6.5%, representing a 0.4% annualized drop in long bond prices.

not yet investible (indeed, many of which do not yet exist), real growth in dividends and earnings is effectively capped *well below* the real growth of the economy. This is the primary reason that real dividend growth has been 1% per year over the past 74 years, in an economy that has grown at 2.5% per year.

Accordingly, while it is very easy to make a case for future real dividend growth that is faster than past growth, it remains very difficult to make a case for sustainable future real dividend growth that is faster than the growth of the economy at large. Are stock buy-backs likely to boost real dividend growth? Of course. Is the higher level of earnings reinvestment likely to boost real dividend growth? Of course. Is the "tech revolution" likely to increase productivity and thus faster economic growth, and can that contribute to faster real dividends and earnings growth? Of course.

But, unless one wishes to postulate real economic growth above 5%, with less than 40% of that growth coming from new enterprises, it is difficult to justify long-term real dividend growth above 3%.

If we assume faster economic growth, and assume that more of this growth reaches today's shareholders than in the past, we can justify real dividends and earnings growth of two or three times the 1% growth that history has delivered. The result is 2% to 3% real dividend growth. In order to forecast a faster real growth rate for earnings or dividends on a long-term sustainable basis, we need to make assumptions that must be viewed as very aggressive, even heroic.

WHAT REAL RETURNS *SHOULD* WE EXPECT?

Summing these, as we do in Exhibit 1, brings the real return up to the 3.2% range, *assuming that current valuation levels hold.* Particularly aggressive growth assumptions (3% growth in real dividends) could stretch real equity returns to perhaps 4.2%, which barely exceeds the government-guaranteed yield on inflation-indexed bonds. An important caveat is that one might just as easily make a case for real dividend growth that is *lower* than the 1% historical growth rate. Either way, this is a far cry from the historical real return of 8%.

More important still, our 3.2% outlook for real returns falls short of the real return available in inflation-indexed government-guaranteed bonds. For the first time in U.S. capital markets history, the equity risk premium is probably negative, barring some very aggressive assumptions regarding economic growth and the share of that growth that makes its way to the investor in today's enterprises.

This result contrasts sharply with the consensus. In a very important draft paper by Ivo Welch, the consensus of 226 academic financial economists was that stocks should outpace Treasury bills by 7% per year over the next 10 and 30 years. If we credit Treasury bills with the historical average real return of 1%, this implies an 8% real return assumption for stocks. The lowest estimated risk premium of the 226 in the survey was a 2% risk premium. There is clearly a huge gap between this consensus, which was probably conditioned by extrapolating the past, and the plausible real return or risk premium in the future. When bond yields fall from 9% to 6%, investors will expect a lower return from bonds. But, as stock dividend yields fall from 4% to 1% (or earnings yields, the reciprocal of the

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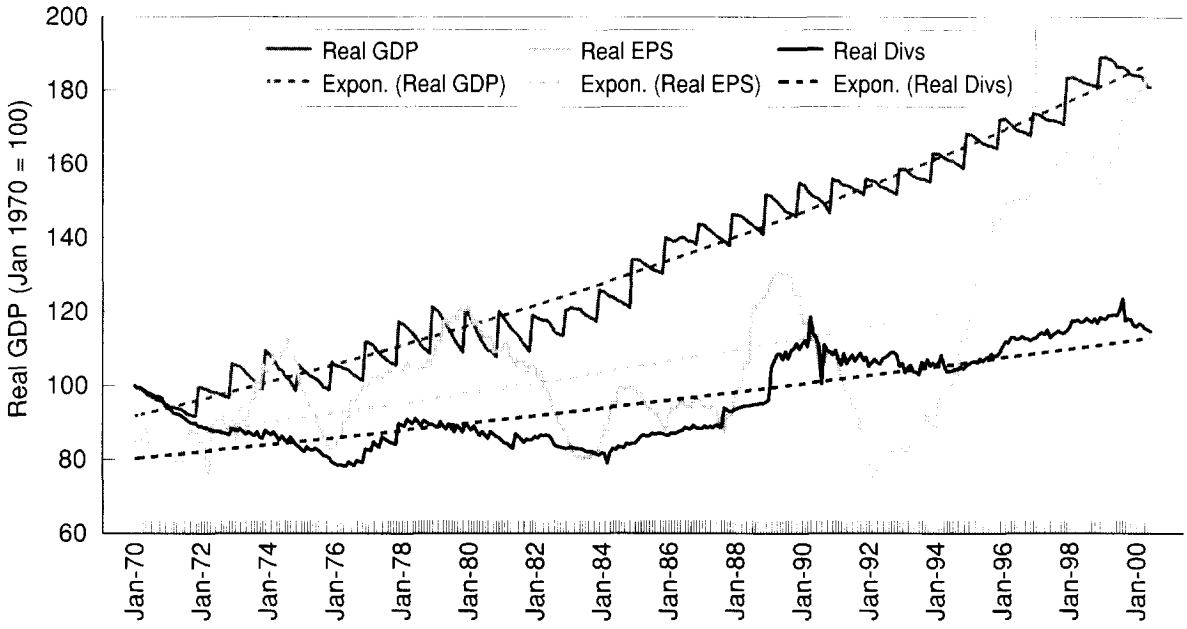
EXHIBIT 2A
U.S.



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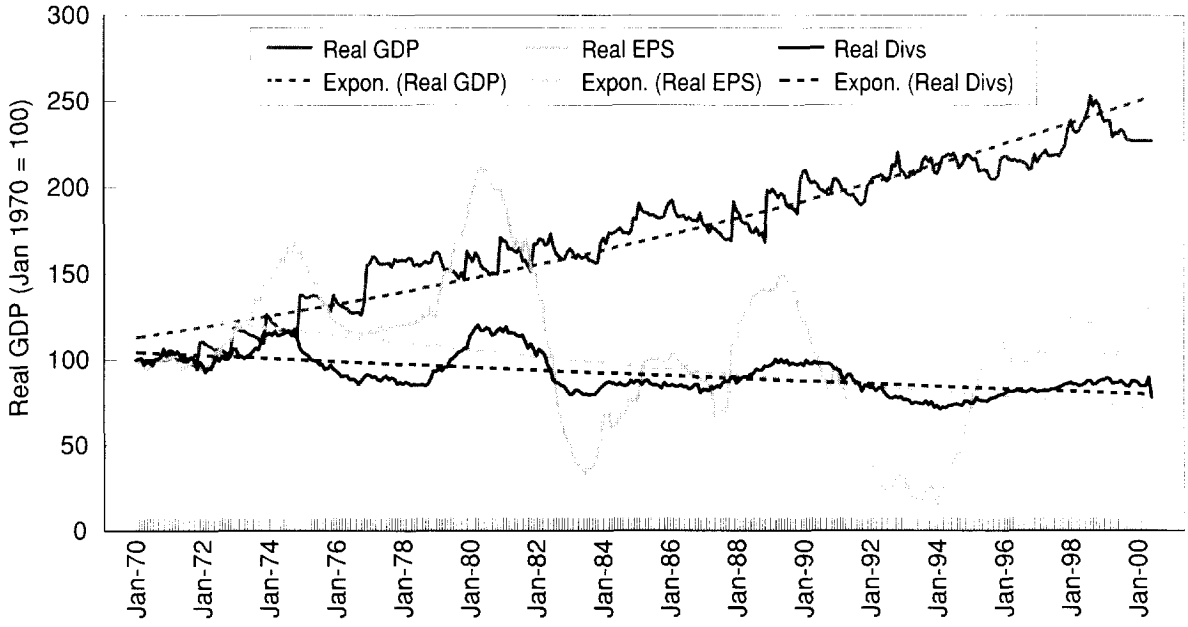
CANADA



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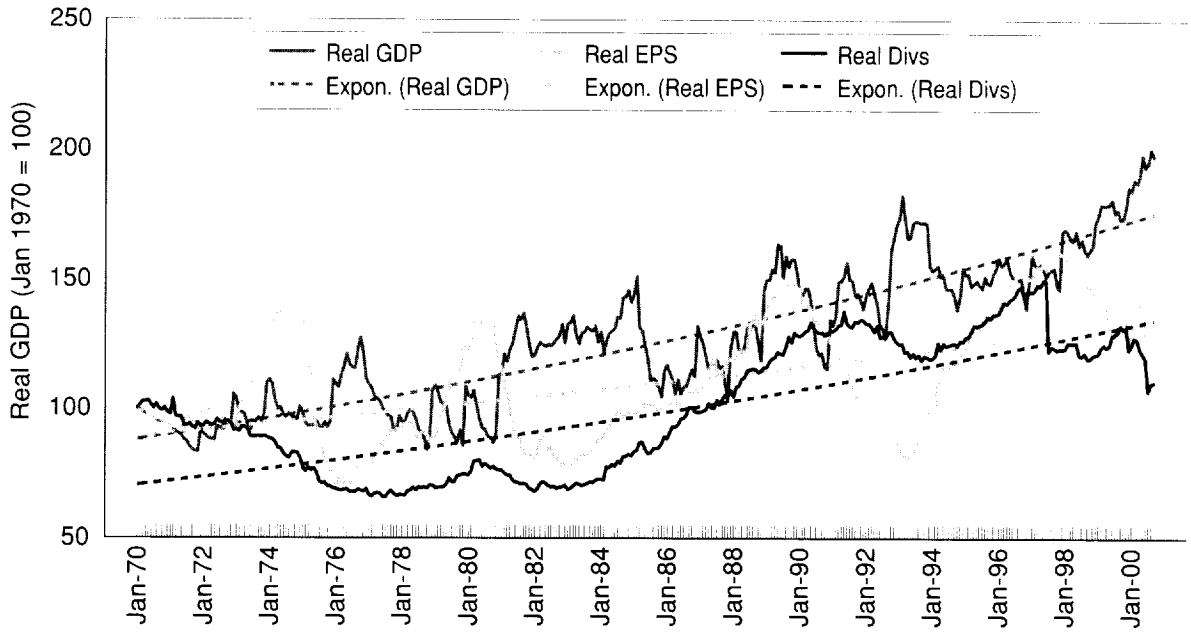

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EXHIBIT 2D
JAPAN

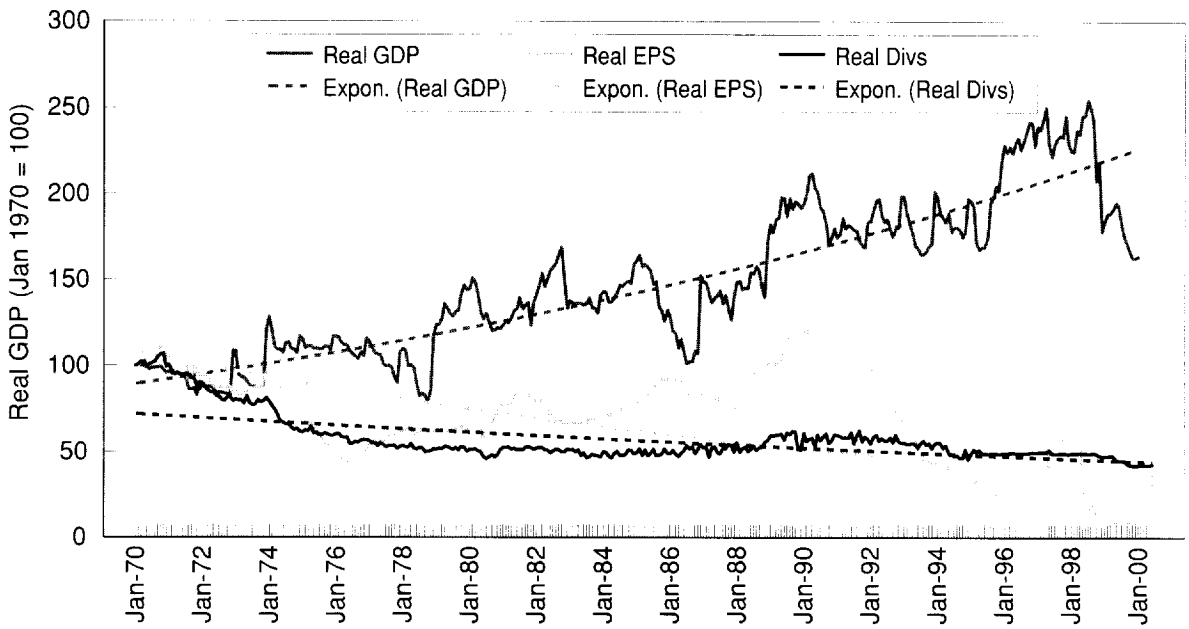

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EXHIBIT 3
GDP GROWTH AND EPS/DIVIDEND GROWTH 1969-1999

	U.S.	Canada	U.K.	Japan	Average
Real GDP	2.3%	2.9%	2.1%	1.6%	2.2%
Real EPS	1.4%	-2.2%	1.3%	-3.4%	-0.7%
Real DIV	1.1%	-0.9%	2.2%	-1.6%	0.2%
Avg(EPS, DIV)	1.3%	-1.5%	1.7%	-2.5%	-0.2%
Avg(EPS, DIV) as % of GDP	54%	-54%	83%	-156%	-11%

price/earnings ratio, fall from 7% to 3%), investors do not reduce their expectations for stock returns. We find this baffling.

WHERE MIGHT WE BE WRONG?

The most important vulnerabilities of our analysis are 1) the assertion that real dividends cannot grow faster than the GDP for long, and 2) the assumption that real GDP growth will not sharply outpace historical rates of growth. Both deserve a closer look.

We have seen that long-term growth of real dividends has been a modest 1% per year for the past 74 years. Is the U.S. experience an anomaly?

Exhibits 2A-2D and Exhibit 3 show the experience over the past 30 years in the U.S., Canada, the U.K., and Japan. If we smooth the growth curves with an exponential line-of-best-fit (the dashed lines in each exhibit), we find that two of these countries have generally seen *negative* "growth" in real earnings and dividends for the past 30 years. Only dividend growth in the U.K. and earnings growth in the U.S. have approximately kept pace with the growth of the economy.

Don't these pockets of success suggest that perhaps dividends or earnings can keep pace with GDP growth? Not really.

- In the U.S., earnings growth roughly matched GDP growth over the last 30 years (although the exponential line-of-best-fit rises barely half as fast as GDP). But, this occurred only because corporate earnings constituted a 70% larger share of U.S. GDP in 1999 as in 1969. Without this *near doubling* of profits, as a fraction of GDP, real earnings growth would have been barely over 1% per year.
- In the U.K., dividend growth roughly matched GDP growth over the past 30 years (here, the exponential line-of-best-fit confirms the growth). But, this occurred only because dividend payout ratios increased by over 50% between 1969 and 1999. Again, without this sharp increase in payout ratios, real dividend growth would have been barely above 1% per year.

Don't stock buy-backs supplant dividends, making the dividend growth both understated and irrelevant? This view is partly correct, but companies cannot sustainably spend more than 100% of earnings on stock buy-backs. If stocks are priced at 30× earnings, then 100% of earnings will suffice to buy back only 3.3% of the outstanding stock. If companies are paying a dividend yield of 1.2%, on average, then the average company can buy back only 2.1% of the outstanding stock with 100% of the retained earnings. Of course, no company can be expected to spend 100% of retained earnings on stock buy-backs, so this represents an upper bound on the potential hidden yield in stock buy-backs.

Why can't the future deliver faster real GDP growth than the past? And, would that not help us to achieve high enough real dividend and earnings growth to achieve a positive risk premium?

Those who argue in favor of unprecedented GDP growth base their outlook primarily on the technology revolution. Any casual observer of the economy would have to agree that the technology revolution is real. Its impact on future GDP growth remains to be seen. It could be modest. After all, we still need to eat food, drive cars, live in homes, and buy toothpaste and soap. Bits and bytes won't and can't replace traditional goods and services, no matter how much they revolutionize information flows and communications. But, technology could materially reduce the costs of production and delivery of goods and services, even as it redefines the world of

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information flows and communications. These productivity increases could lead to far more rapid GDP growth than we've seen in the past. A new Industrial Revolution could easily be in the works.

Let's take it as a given that GDP growth will materially exceed the 2.5% to 3.0% that has been normal for much of the past century. A key question: How much of this growth will come from growth in existing enterprises, and how much will come from the creation of new enterprises?

Advocates of a new Industrial Revolution would be the first to acknowledge that most of this faster-than-ever-before growth must come from the creation of new enterprises, many of which have not yet even been conceived. Investors in current enterprises *cannot* participate in GDP growth that comes from the creation of new enterprises. This means that the growth in earnings and dividends on existing enterprises *must* be slower than the growth in GDP, because of the dilution effect of new enterprise creation.

History suggests that this dilution takes place at a rate of roughly 1% to 2% per year. This means that earnings and dividend growth has been 1 to 2 percentage points lower than GDP growth, in both the U.S. and other markets, once we adjust for increases or decreases in the ratio of earnings or dividends as a fraction of GDP.

This seems modest until one considers that 3% GDP growth is generally considered a solid rate of long-term economic growth. A 1 or 2 percentage point haircut means that today's equity investors participate in only one-third to two-thirds of the total GDP growth, forfeiting the remainder to those who create new enterprises. This seems a remarkable gap, difficult to accept until one considers that:

- This has indeed been the norm in the four large economies that we have studied, as shown in Exhibits 2 and 3.
- Over 55% of the capitalization weight in the Russell 3000 index consists of companies that did not exist 30 years ago, which corresponds to roughly 2.5% per year of GDP growth stemming from the creation of new enterprises.

Venture capital investors *can* participate in the growth that stems from new enterprise creation, at substantial costs, and with substantial dilution of those gains. The entrepreneurs and the venture capitalists will tend to take a very large (and not inappropriate) first slice of the growth associated with these ventures. But, it is impossible for the same dollar of investment capital to participate in *both* the growth of existing enterprises *and* the creation of new enterprises.

Also, such enterprises often have low marginal reliance on capital, with great reliance on *skilled* labor with portable knowledge. If the marginal return to (skilled) labor is high, and if the barriers to entry in many of these enterprises are low, it will be unsurprising if the marginal return to capital is low. This would mean that the long-term future rewards to capital are not necessarily higher for these investments than for conventional equity investments.

WHAT ARE THE IMPLICATIONS OF A NEGATIVE RISK PREMIUM?

The implications of a negative risk premium are far-reaching and profound. Perhaps the most important issue is that actuarial return assumptions in pension funding today may be too aggressive. If prospective returns fall short of actuarial assumptions, then contributions must rise. If contributions do not rise today, then future contributions must rise still further, in order to catch up for underfunding of today's obligations.

The typical range of actuarial real return assumptions falls in a range from 4.5% to 7.5%. Our own evaluation of prospective returns suggests that something in the range of 3.5% is probably more realistic. Given the fact that most pension funds have a duration of 12 to 15 years, any error in actuarial real return assumptions can have a considerable impact on the true funding ratio of a pension portfolio.[1]

For instance, suppose a pension fund has a very solid 150% ABO funding ratio.[2] If such a fund were assuming a 4.5% real return, yet earned a 3.5% real return, the true funding ratio would actually be 132%. If this fund were assuming an aggressive 7.5% real return, this 4 percentage point difference in real returns would mean that the true funding ratio is an appalling 90%. What is perceived as a healthy overfunded pension fund, with a substantial surplus, turns out to be underfunded.

If we can *anticipate* that returns will be lower than the prevailing actuarial assumptions, we have a number of choices that we can make.

- We can choose to stay with the current assumptions, recognizing that catch-up contributions will probably be needed. This is the path of least resistance, and is a path that many actuaries will not

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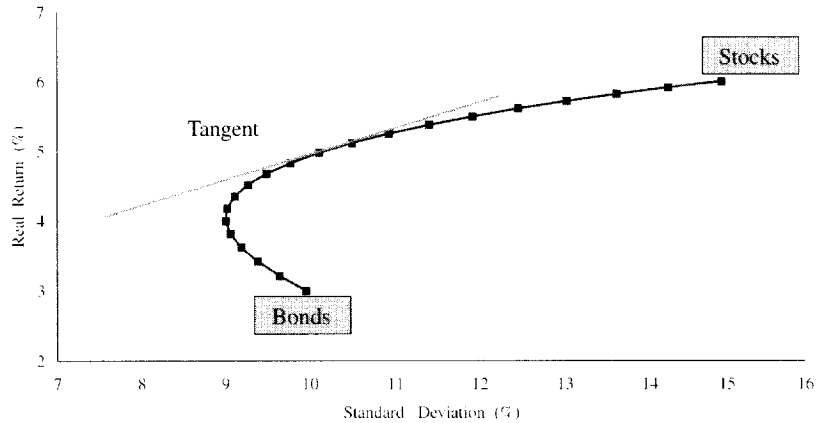
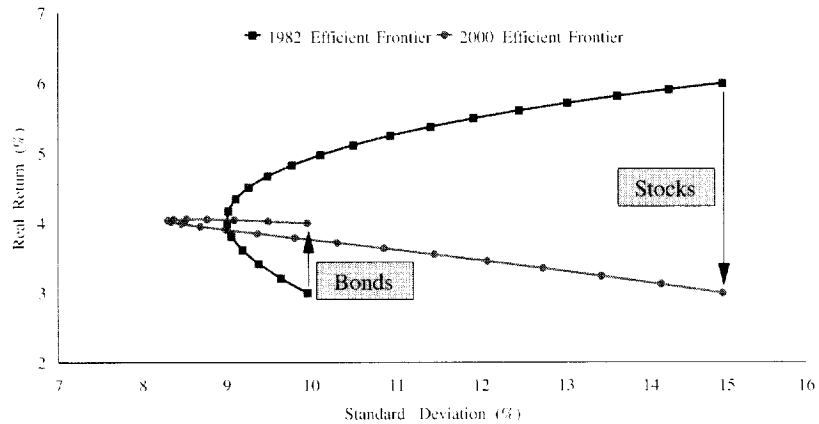
EXHIBIT 4A
1982 EFFICIENT FRONTIER



Simulation based on S&P historical returns.

EXHIBIT 4B
THE NEW EFFICIENT FRONTIER?



Simulation based on S&P historical returns.

resist, because their own return expectations are based on an extrapolation of the past ... they just don't believe that the risk premium could possibly be gone! If actual returns fall short of actuarial return expectations over the next several years, and if contributions are artificially depressed due to overly optimistic return assumptions, the result will be a large number of sponsors a few years hence with unfunded liabilities.

- We can choose to lower our actuarial return assumptions a little bit, in order to increase funding of the pension portfolio, but not to reduce return assumptions all the way to 3.5%. This probably means that some catch-up contributions will still be needed, but the fund sponsor will not be taking the lead by using sharply more conservative assumptions than its competitors. This can lead the sponsor to be better funded when actuarial return assumptions of its competitors eventually follow suit, thereby holding a stronger competitive position vis-à-vis competitors, with lower labor costs, stronger cash flow, and higher earnings.
- Or, we can choose to move all the way to the real returns that are likely to be sustainable from today's market levels, which would imply real return assumptions in the 4% range or less. This way, there will be no catch-up contributions required. The consequences are much more aggressive contribution to the pension portfolio and lower earnings. This weakens the *current* competitive posture of the pension sponsor relative to its peers in exchange for strengthening its *future* competitive posture with regard to its peers.

The correct choice likely depends on the health of the pension sponsor relative to its competitors or peers. It is not an easy choice; it is a painful choice.

Another nuance of the negative risk premium is that the efficient frontier "flips." In Exhibit 4, we can see an illustrative efficient frontier drawn from 1982. In 1982, stocks offered a dividend yield as high as 5.5%. It would have been very easy, at the time, to anticipate a 6% real return from equities. This expectation would imply only a 0.5 percentage point real growth in the market value assigned to each dollar of earnings or dividends. At the same time, bond yields had tumbled to just 3 percentage points above consensus inflation expectations. The consequence was the classic efficient frontier that we see in Exhibit 4A.

In today's market, we can earn roughly 4% real from inflation-indexed government-guaranteed bonds, but a reasonable expectation for equity real returns is probably in the 3% range. This transition is illustrated in Exhibit 4B. If we are correct, this would leave the current efficient frontier "flipped," or inverted, to the frontier that we see in

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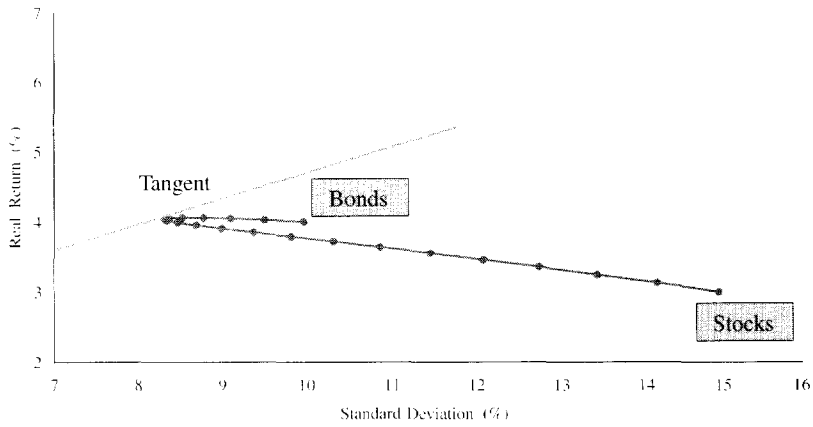
EXHIBIT 4C
2000 EFFICIENT FRONTIER?



Simulation based on S&P historical returns.

Exhibit 4C. A flipped efficient frontier has profound and far-reaching implications for policy asset allocation.

- In the past, the easy way to boost long-term return expectations was to put more in equities. This no longer works.
- In the past, equities were the asset class of choice for boosting returns. With a flipped efficient frontier, they become merely another diversification alternative for controlling portfolio risk. In a world of 15% returns, adding 2 percentage points through successful active management (or losing the same in a failed quest for alpha) is not terribly important. In a world of 3.5% real returns, adding or forfeiting 2 percentage points suddenly matters a great deal. The quest for alpha becomes terribly important, and the avoidance of negative alpha becomes commensurately important.

THE EARNINGS IMPLICATIONS OF ACTUARIAL ERROR

One little-explored nuance of the risk premium and of actuarial return assumptions is found in the prospective impact on corporate earnings. Corporate earnings have a component (pension expense if negative and pension earnings if positive) that is tied directly to how well the pension fund fares relative to actuarial return assumptions. It is the cost of funding the pension, less the actuarial expected rate of return for the pension portfolio.

If this is a profit center, meaning that pension obligations are growing more slowly than pension assets, this "profit" may actually go away with even a modest reduction in the actuarial real return assumptions. By the same token, if it is not a profit center (i.e., if actuarial pension obligations are rising faster than the actuarial returns on the fund), the cost of the pension will increase if a lower real rate of return is assumed.

Either way, the earnings of a company fall if the actuarial return assumption is reduced. This impact can be startlingly large.

For the Russell 3000, for instance, total defined-benefit pension assets are around $2 trillion. If the average fund is using a real return assumption that is 3% too high, and if the average fund has a duration of 12 years, then the average fund has a true pension liability that is over 40% higher than the actuarial estimate. If this $800 billion understatement of actuarial surplus is amortized over a ten-year span (keeping in mind that the Department of Labor requires five-year amortization if a plan is actually underfunded), then earnings are overstated by some $80 billion per year.

This means that a year-end 2000 P/E ratio of 28 times latest 12-month earnings for the Russell 3000 translates into a true P/E ratio, adjusted for realistic actuarial pension returns, of some 34 times true earnings. This hidden consequence of reduced future returns means that the U.S. stock market is almost 20% more expensive than it seems.

DO RETURNS REALLY MATTER?

It goes without saying that pension fund assets do not exist in a vacuum. What is often overlooked is that liabilities have returns too, and that these returns move with the capital markets, most notably with bonds.

Exhibit 5 suggests that 1999 was an extraordinary year for pension funds, because assets went up materially, and the net present value of liabilities went down. By the same token, 1995, which most people thought was a wonderful year for returns, was a dreadful year for funding ratios, due to the tremendous increase in the net present value of liabilities.

What of the decade of the 1990s? As Exhibit 6 suggests, the decade was very good, but not as good as most people think. With interest rates falling during the course of the decade, liabilities rose in value by enough to offset much of the gain in asset values.

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EXHIBIT 5
AVERAGE PENSION FUND: TYPICAL EXPERIENCE IN 1999

	1999	1995
Liabilities (Ryan Labs Liability Index)	-12.70%	41.16%
Asset Allocation:		
5% Cash (Ryan Labs Cash Index)	4.24%	7.11%
30% Bonds (Lehman Aggregate)	-0.82%	18.47%
60% Equity (S&P 500)	21.53%	37.57%
5% Intl (MS EAFE)	27.35%	11.56%
Total Assets	14.25%	28.67%
Assets – Liabilities	26.95%	-12.49%

A typical, if not conservative, asset allocation ratio shows what the average pension fund should have experienced in 1999.

CONVENTIONAL WISDOM OF THE 1990S

The decade of the 1990s was in some ways a continuation of the prior decade. Markets delivered robust returns, this time from starting valuation levels at or above long-term historical norms. The consequence has been a panoply of lessons learned, some sensible, some flagrantly flawed.

That the 1990s Have Left Us Well-Funded?

Many pension plans believe they have built a reservoir of actuarial pension surplus so that the plan does not have to make contributions for a very long time. On closer examination, these plans tend to have a real return assumption for assets that resembles, or is explicitly based upon, the past. A 5%-8% real return is not uncommon (even considered conservative by some). Most pension plans use return assumptions between 8% and 10%, some even higher, with inflation assumptions typically around 2% to 3%.

This is typically considered defensible, since most institutional portfolios have achieved consistent real returns comfortably above 10% for the last 5, 10, 15, 20, and even 25 years. Yet, as we have already seen, real returns of 3% to 4% are a more realistic expectation, in today's markets.

What if a 3% to 4% real return assumption is used for the funding ratio? Many pension plans would be materially underfunded. The typical pension fund has a duration of 12-15 years, meaning that a 1 percentage point change in the discount rate or in the return assumption leads to a 12%-15% change in funding ratios. Yet, we have already seen that 3% to 4% is a reasonable real stock market return expectation from current market levels, and that 5% or more requires some rather aggressive assumptions.

If real return assumptions are cut by 2 or 3 percentage points from current levels, most funds would find their ABO funding ratio drops by 25% to 40%. For example, a fund that has a lofty "official" ABO funding ratio of 160% might find the true ratio is 96% to 120%.

That Stocks Are the Best Investment for Long-Term Investors?

Stocks have outperformed government bonds by over 5% per year over the past 74 years, and by a far wider margin over the past 10 to 25 years. Stocks have exceeded inflation by over 8% a year for the past 74 years, and, again by a far wider margin during the 1990s.

But extrapolating the past is one of the most common and dangerous ways to forecast the future. The past is not prologue. In fact, there is a modest, but significant, negative correlation between long-term past returns and subsequent future long-term real returns.

Any student of history can point to extended periods in which stocks have not produced an excess return. From the end of 1961, an investment in Treasury bills outpaced both stocks and bonds through mid-1982, a span of 20-plus years. From the 1929 market peak, stocks underperformed bonds over the subsequent 17 years and needed 25 years to outpace Treasury bills. For the investor in 1801, by some measures, stocks merely matched bonds over the subsequent 70 years.

That to Boost Funding Ratios, Boost Returns: Invest More in Stocks?

Given that the long-term inflation-linked bonds (TIPS) are yielding over 4% today, there is a government-insured risk-free real return vehicle that not only could beat stocks over the next 20 years, but probably *will*. It is our view that extrapolations of the past have been used to justify a shift in asset mix for the average pension fund from roughly a 50/50 stock/bond mix in 1980 to roughly a 75/25 mix in 2000. The evaporation of the risk premium lays a foundation for a legitimate reexamination of the appropriate policy asset mix and of the key assumptions for that mix.

The traditional asset allocation approach is to seek the highest possible absolute return at an acceptable level of volatility (risk). This view of risk and reward appears in the graph that plots the asset returns on the vertical axis

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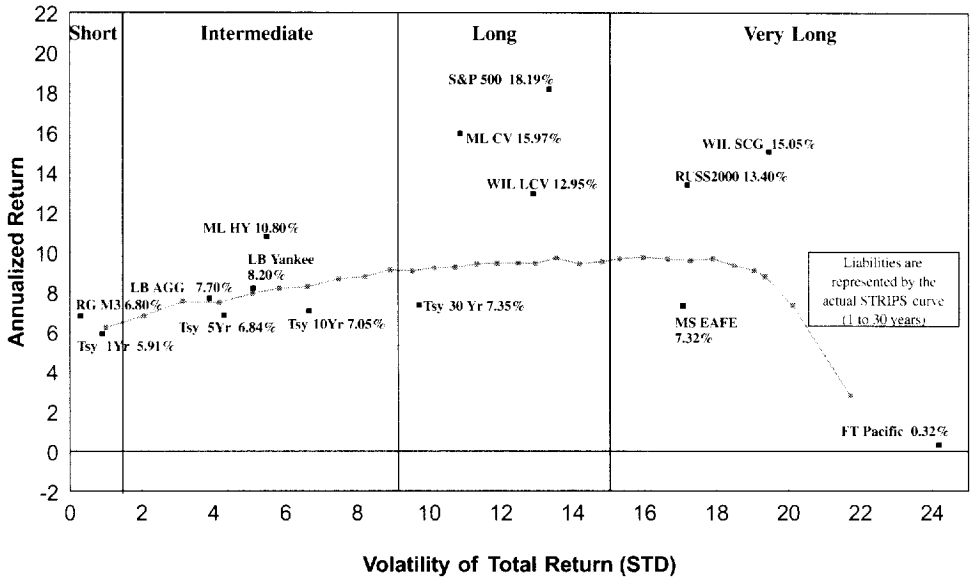
EXHIBIT 6
ASSET/LIABILITY MONITOR (TEN-YEAR PERIOD ENDING 12/31/99)



and the variability of returns (standard deviation) on the horizontal axis. Most asset allocation models tend to be silent on the subject of pension liabilities. That is, they tell pension management nothing about where the pension plan should be positioned vis-à-vis the liabilities. Organizations with mature work forces (shorter liabilities) should hardly want the same asset allocation as organizations with young work forces (longer liabilities).

One way to think about the correct role of liabilities in fund management is to redefine risk relative to those liabilities. In so doing, the risk-minimizing portfolio is *not* T-bills, but instead the mix of assets that offers the best fit with the liabilities (liability index fund). And, the optimal portfolio is the portfolio that offers the best increment of return above the return of the liabilities, with acceptable risk relative to the liabilities.

If the shape of pension liabilities shapes the asset allocation process, then a fully funded risk-minimizing plan for an older mostly retired work force, with 20% in long-term liabilities (liabilities longer than ten years), would allocate only 20% to long assets, while another risk-minimizing plan for a young work force, with 80% in long liabilities, would allocate 80% to long assets. Indeed, we would argue that asset allocation should strive to optimize the *relative* return of assets (asset growth) to the growth in liabilities.

Exhibit 6 shows a line that represents the annual growth rate of liabilities for each year of liabilities up to 30 years over the 10-year period ending December 31, 1999. Please note the risk/reward behavior of assets (the black boxes) versus the points on the liability line. Vertical lines separate the short, intermediate, long, and very long assets and liabilities. Notice that cash equivalents behave like very short liabilities; bonds behave like intermediate liabilities; long STRIPS (Treasury zero-coupon bonds) and stocks behave like long liabilities; and international securities behave like very long liabilities.

MSCI EAFE is a case in point. Even though it outperformed the one-year T-bill, it severely underperformed the very long liabilities that it behaves most like (volatility). At least during the 1990s, EAFE would not have been a good asset allocation choice to fund very long liabilities. In fact, very long Treasury STRIPS would have outperformed EAFE by a considerable margin, and would have funded the liabilities without risk.

Asset allocation is a risk/reward decision between the low-risk liability-matching asset (Treasury STRIPS) and an asset class that will outperform this liability area with similar volatility (risk). It is not a contest to find the highest absolute return. You would not buy stocks to fund short liabilities, because their risk/reward behavior is not appropriate. Nor should you buy cash equivalents to fund long liabilities.

Asset allocation is the process of matching the volatility of liabilities with assets that can generate the same or greater growth. The S&L crisis is still a vivid les-

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son of what happens when you mismatch assets to liabilities by risk or volatility patterns.

That Liability Matching Is Less Important Than Asset Returns?

Pension fund assets have grown to a point where they often make up the bulk of a company's or public sponsor's total assets. The variability and rate of return of the pension assets affect company profitability and budgets and a sponsor's tax rates. In both cases, pension "success" has enormous (even if smoothed) impact on competitiveness with one's peers, company against company or state against state. So pension sponsors have an obligation to give the pension fund as much attention as any significant operating division.

Traditionally, actuaries provide low asset/liability volatility (smoothing) by adjusting return assumptions on the assets and discount rates for the liabilities with only modest change from year to year. Reality is much different. Appropriate discount rates for liabilities move every bit as quickly as bond yields change. Appropriate return assumptions move every bit as quickly as changes in bond yields and stock earnings yields (the reciprocal of the price/earnings ratio, itself a crude proxy for forward-looking real stock market returns).

The difference between these forecasts and reality is then amortized over some long average life. As a result, pensions have misunderstood the true objective of pension thinking: that the actuary estimate is their target growth rate for assets.

Enter FASB 87, which rules that the interest rate risk employed to calculate the present value of the liabilities is no longer the actuary's province. Market interest rates must now serve that purpose, so that liabilities are priced as if they were a portfolio of high-quality zero-coupon bonds whose maturities match the liability payment dates and whose par values match the liability payment amounts. While there is a certain latitude available to the actuary in selecting a rate that is *near* this market rate, liabilities are now more correctly calculated and are now seen as a volatile, and extremely interest rate-sensitive, part of the pension puzzle.

But, even as liability discount rates are forced to be more strongly based on market yields, actuaries have wide latitude in inflation assumptions and in the return assumption for the assets. This latitude is liberally used to provide a very steady real return assumption, at a level that is not altered to reflect market valuation levels.

THE "RIGHT WAY" TO VIEW THE ASSET/LIABILITY PUZZLE

The way we deal with risk depends on how we define it. This is often a more complicated task than appears. In pensions, risk is not funding liabilities correctly. Since pension assets are the primary source of funding liabilities, risk here can be measured only when you compare the risk/reward of assets vis-à-vis the liabilities they are funding. *The no-risk asset is the asset that funds the liability with certainty.* A risky asset is one that has much uncertainty about its risk/reward behavior vis-à-vis the liability it is funding. The risk-free asset to fund a ten-year fixed liability would be a ten-year Treasury zero-coupon bond (STRIPS).

This is why FASB ruled that liabilities are to be priced as high-quality zero-coupon bonds, because they represent the no-risk portfolio. Assets are to be compared to this zero-coupon liability portfolio to understand the relative risk and reward such assets produce in their goal to fund liabilities.

Until the growth rate and the volatility of liabilities are correctly measured and analyzed, pension risk can never be understood and managed properly. Since all pension liabilities are different and unique to each plan, only a custom liability index could represent the true pension liability objective. Once a custom liability index is designed, then and only then can we make the policy asset allocation decisions, notably, the appropriate departures from the risk-minimizing portfolio. The risk-minimizing asset allocation depends on a custom liability index for its shape of liabilities.

Proper asset management and performance measurement should be a constant monitoring of assets compared to liabilities. Generic market indexes may help us to understand the risk/reward behavior of certain markets, but they can never tell you the risk/reward behavior of your portfolio *relative to the liabilities.* As basic as it sounds, the pension industry has operated with the wrong objective since birth. Outperforming a generic market index is not the objective. *Outperforming liabilities with acceptable volatility, relative to those liabilities, is the objective.*

Surplus Management in the Years Ahead

1999 was a stellar year for the pension industry, just as 1995 was truly awful. How can this be, when returns in 1999 were less than half the returns of 1995? The problem in 1995 was that liability returns were spectacular as a consequence of falling interest rates. 1999 was stellar because assets for most funds rallied while liabilities actually tumbled, as a consequence of rising interest rates.

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The capital markets have granted the pension industry a "reprieve," an opportunity to reexamine the basic assumptions that form the basis for policy allocation decisions, at a time when liabilities have fallen sharply and funding ratios have soared.

Given that the asset/liability ratio should have improved by about 25% in 1999, it is timely to reappraise the asset/liability strategy. If there is a meaningful pension surplus, it would be wise to separate the surplus assets into a distinct and separate objective portfolio. This portfolio could welcome almost any type of asset allocation since the investment time horizon is in perpetuity, and there are no liabilities funded from this portfolio. More aggressive investments that have great potential but need time to develop would be ideally suited to this portfolio.

It would seem practical to have a long-term growth rate target as the proper benchmark here rather than the traditional "beat thy neighbor" peer group contest traditionally run in pension land.[3] There are several ways to manage fund surplus, in the context of liabilities.

Strategy I: Surplus Portfolio (Ongoing Plan). The strategy here is to secure the pension surplus and facilitate surplus growth through the surplus portfolio, not the A/L portfolio. To secure the pension surplus requires the asset/liability portfolio to be strictly managed to pay liabilities when due. This would suggest a cash flow-matching strategy.

The retired lives liability is an obvious candidate for this strategy since these liabilities are the most important and the most certain. The active lives liability is less certain and has some volatility, but it too needs a strict asset/liability strategy, since that is the objective of these assets. The idea is to make funding liabilities properly the objective instead of some generic market indexes that may have no correlation at all to the clients' liability schedule.

A custom liability index that best fits each client's unique liability schedules represents the liability objective. Once calculated and maintained, a custom liability index fund would be the best strategy to fund this liability at the lowest cost and the lowest risk to the plan.[4]

The assets that are not required to match the known liabilities constitute the pension surplus. These assets can then be managed in a fashion that matches the plan sponsor's appetite for returns and tolerance for risk.

Strategy II: Liability Defeasance (Terminated/Converted Plan). Under IRS Section 417, a company can defease liabilities in a plan termination or conversion by pricing them at the average of the bond-equivalent yield (BEY) of the 30-year Treasury for the month of December prior to termination. This rate is locked in for one full calendar year. Calendar year 2000 has been expected to enjoy the highest rate (lowest cost) since 1996 (1996: 6.55%, 1997: 6.00%, 1998: 5.05%, 1999: 6.35%).

Defeasement means that a company matches its portfolio of liabilities with assets of equal value, dedicated to meeting the projected payouts and thereby securing the pensions for the retirees. By doing this, the law permits the company to remove the liability from the balance sheet, thereby improving its financial ratios. In addition, the company is permitted to take a reversion and remove any surplus assets from the pension plan for its own use, paying taxes and in some cases modest penalties for access to these assets.

Defeasement, by definition, requires a 100% bond portfolio, with heavy emphasis on zero-coupon bonds cash flow-matched to the liability payout schedule. Once defeased, surplus is now the property of the employer rather than the employees. It can be used for any corporate purposes, as it is now part of retained earnings. Financial ratios are also enhanced, thereby reducing debt ratios and improving creditworthiness.

It should be noted that there are costs and consequences of defeasement that make this an unappealing alternative for any but the most mature and risk-averse sponsors. In the act of defeasing and removing surplus from the fund, the sponsor is walking away from an opportunity to shelter current and future income from taxes as well as an opportunity to invest on a tax-deferred basis. Funds invested in a pension fund avoid current tax, and accumulate on a tax-exempt basis.

A pension fund, managed on a going-concern basis, can reduce future pension funding costs. Accordingly, asset returns in excess of liabilities serve to reduce future pension contributions dollar-for-dollar on tax-exempt earnings.

Asset Management in the Context of Liabilities

For the going concern, an exact match of assets to liabilities is clearly not necessary. It is merely one of many interesting alternatives. Even if an exact match is selected as a means of managing pension risk, the surplus (the residual assets above those required to defease the liabilities) is a very interesting vehicle for tax-deferred and tax-exempt investing of company resources.

But these decisions should be made in the context of the liabilities; frequently they are not. If nothing else, the fund sponsor should be well aware of 1) the nature of the liabilities, 2) the mismatch between the assets and the liabilities, and 3) the corresponding risks taken with what, in truth, is a company asset, the surplus.

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A CALL FOR ACTION?

Suppose we are correct that the equity risk premium is gone. Suppose we are correct that real returns on stocks are likely to be in the 3%–4% range for the foreseeable future (10–20 years). Suppose we are correct that the real returns the actuaries assume are no longer sensible. What does this all mean?

1. It is more appropriate now than ever before to revisit the policy asset mix for a portfolio. Funds have drifted to a 70%–80% equity stance as the accepted norm, at a time when the equity excess return over bonds appears to have vanished, up from 50%–60% 20 years ago.
2. Funding ratios are probably not as healthy as they appear. This presents companies (and states and counties) with a choice. Do we continue to make assumptions that are no longer realistic, in order to keep pension contributions down? This implies that future funding must cover not only the future costs of pension obligations, but also catch up payments for today's arrears. Or, do we move in the direction of more realistic assumptions in order to improve our *future* competitive position by fully funding current obligations and enjoying the tax-exempt returns that can save us substantially on future contributions? There is no right answer to this question—but it is a question that must be asked, and of late has not received much attention.
3. If returns don't necessarily improve pension health and wealth, due to the subtle interplay between asset and liability returns, what is the return objective? We would posit that a 10% market rally boosts fund wealth by a small fraction of 10%, due to the reduction in subsequent prospective rates of return. On the other hand, 10% earned through alpha is a true 10% improvement in fund health, by any measure. Accordingly, the quest for alpha is a key aspect of the fund management puzzle.

Following the decade of the 1990s, which took the forward-looking real returns available from stocks to all-time lows, and the experience of 1999, which improved funding ratios to the best seen since 1996, fund sponsors owe themselves a careful reexamination of their asset allocation policies, beginning with a reevaluation of their key assumptions.

ENDNOTES

[1]The duration of a pension fund is a measure of the sensitivity of funding ratios to any change in return assumptions. In effect, the duration measures how much the funding ratio would change with a 1% change in return assumptions. For instance, a duration of 12 years would mean that a 1% change in real return assumptions would trigger a 12% change in funding ratios. This is closely related to the liability duration, which is the number of years until the *average* current obligation becomes payable, weighted by the dollar value of that liability. The two concepts are interconnected and tend to be a similar number.

[2]ABO funding ratio is the *accumulated benefit obligation*. This is the net present value of current obligations of a defined-benefit or cash balance pension portfolio, discounted at the actuarial discount rate, credited with the actuarial return assumption, and reflecting only the pension obligation that is due and payable as a consequence of current years of service. No prospective growth in pension obligations from future years of service, from future wage inflation, or from future changes in the benefit formulas, or from future returns that are above or below the actuarial return assumption is considered.

[3]The decisions of one's peers and competitors should not be the key determinant of asset allocation policy, although they often tacitly are. That said, we would readily acknowledge that "maverick risk" (the risk of underperforming one's peer group or competitors) is not without import or merit. It is important, if only because of the career risk that accompanies large departures from one's peer group. It has merit if only because underperforming one's peers means higher future pension costs than one's peers, hence a lower profit margin (or, for public funds, higher taxes) than one's peers, assuming the liability structures are comparable.

[4]Some words of caution about traditional immunization (cash flow matching). Immunization tries to match the present value of assets to the present value of liabilities. Too often this is implemented by matching the average modified duration of the asset portfolio to the liability portfolio. Duration-matched immunization models do not fit the cash flows with precision. The risk match is good, but distinctly less than exact: If the slope of the asset pricing yield curve or the liability pricing yield curve changes its shape, immunization models will usually fail. Only when the entire term structure is matched (all liability payments) is cash matching optimal. This is why a custom liability index fund represents a better fit, since the entire term structure is matched, not just the average duration.

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Forecasting US Equity Returns in the 21st Century

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What returns should investors expect the US stock market to deliver on average during the next century? Does the experience of the last century provide a reliable guide to the future? In this short note I first discuss alternative methodologies for forecasting average future equity returns, then discuss current market conditions, and finally draw conclusions for long-term return forecasts. Throughout I work in real, that is inflation-adjusted, terms.

I. Methods for forecasting returns

1. Average past returns

Perhaps the simplest way to forecast future returns is to use some average of past returns. Very naturally, this method has been favored by many investors and analysts. However there are several difficulties with it.

a) *Geometric average or arithmetic average?* The geometric average return is the cumulative past return on US equities, annualized. Siegel (1998) studies long-term historical data on value-weighted US share indexes. He reports a geometric average of 7.0% over two different sample periods, 1802–1997 and 1871–1997. The arithmetic average return is the average of one-year past returns on US equities. It is considerably higher than the geometric average return, 8.5% over 1802–1997 and 8.7% over 1871–1997.[1]

When returns are serially uncorrelated, the arithmetic average represents the best forecast of future return in any randomly selected future year. For long holding periods, the best forecast is the arithmetic average compounded up appropriately. If one is making a 75-year forecast, for example, one should forecast a cumulative return of 1.085^{75} based on 1802–1997 data.

When returns are negatively serially correlated, however, the arithmetic average is not necessarily superior as a forecast of long-term future returns. To understand this, consider an extreme example in which prices alternate deterministically between 100 and 150. The return is 50% when prices rise, and -33% when prices fall. Over any even number of periods, the geometric average return is zero, but the arithmetic average return is 8.5%. In this case the arithmetic average return is misleading because it fails to take account of the fact that high returns always multiply a low initial price of 100, while low returns always multiply a high initial price of 150. The geometric average is a better indication of long-term future

[1]When returns are lognormally distributed, the difference between the two averages is approximately one-half the variance of returns. Since stock returns have an annual standard deviation of about 18% over these long periods, the predicted difference is $0.18^2/2 = 0.016$ or 1.6%. This closely matches the difference in the data.

prospects in this example.[2]

This point is not just a theoretical curiosity, because in the historical data summarized by Siegel, there is strong evidence that the stock market is mean-reverting. That is, periods of high returns tend to be followed by periods of lower returns. This suggests that the arithmetic average return probably overstates expected future returns over long periods.

b) *Returns are very noisy.* The randomness in stock returns is extreme. With an annual standard deviation of real return of 18%, and 100 years of past data, a single year's stock return that is only one standard deviation above average increases the average return by 18 basis points. A lucky year that is two standard deviations above average increases the average return by 36 basis points. Even when a century or more of past data is used, forecasts based on historical average returns are likely to change substantially from one year to the next.

c) *Realized returns rise when expected returns fall.* To the extent that expected future equity returns are not constant, but change over time, they can have perverse effects on realized returns. Suppose for example that investors become more risk-tolerant and reduce the future return that they demand from equities. If expected future cash flows are unchanged, this drives up prices and realized returns. Thus an estimate of future returns based on average past realized returns will tend to increase just as expected future returns are declining.

Something like this probably occurred in the late 1990's. A single good year can have a major effect on historical average returns, and several successive good years have an even larger effect. But it would be a mistake to react to the spectacular returns of 1995–99 by increasing estimates of 21st Century returns.

d) *Unpalatable implications.* Fama and French (2000) point out that average past US stock returns are so high that they exceed estimates of the return to equity (ROE) calculated for US corporations from accounting data. Thus if one uses average past stock returns to estimate the cost of capital, the implication is that US corporate investments have destroyed value; corporations should instead have been paying all their earnings out to stockholders. This conclusion is so hard to believe that it further undermines confidence in the average-return methodology.

One variation of the average-past-returns approach is worth discussing. One might take the view that average past equity returns in other countries provide relevant evidence about US equity returns. Standard international data from Morgan Stanley Capital International, available since the early 1970's, show that equity returns in most other industrialized countries have been about as high as those in the US. The exceptions are the heavily commodity-dependent markets of Australia and Canada, and the very small Italian market (Campbell 1999). Jorion and Goetzmann (1999) argue that other countries' returns were

[2]One crude way to handle this problem is to measure the annualized variance of returns over a period such as 20 years that is long enough for returns to be approximately serially uncorrelated, and then to adjust the geometric average up by one-half the annualized 20-year variance as would be appropriate if returns are lognormally distributed. Campbell and Viceira (2001, Figure 4.2) report an annualized 20-year standard deviation of about 14% in long-term annual US data, which would imply an adjustment of $0.14^2/2 = 0.010$ or 1.0%.

lower than US returns in the early 20th Century, but this conclusion appears to be sensitive to their omission of the dividend component of return (Dimson, Marsh, and Staunton 2000). Thus the use of international data does not change the basic message that the equity market has delivered high average returns in the past.

2. Valuation ratios

An alternative approach is to use valuation ratios—ratios of stock prices to accounting measures of value such as dividends or earnings—to forecast future returns. In a model with constant valuation ratios and growth rates, the famous Gordon growth model says that the dividend-price ratio

$$\frac{D}{P} = R - G, \tag{1}$$

where R is the discount rate or expected equity return, and G is the growth rate of dividends (equal to the growth rate of prices when the valuation ratio is constant). This formula can be applied either to price per share and conventional dividends per share, or to the total value of the firm and total cash paid out by the firm (including share repurchases). A less well-known but just as useful formula says that in steady state, where earnings growth comes from reinvestment of retained earnings which earn an accounting ROE equal to the discount rate R,

$$\frac{E}{P} = R. \tag{2}$$

Over long periods of time summarized by Siegel (1998), these formulas give results consistent with average realized returns. Over the period 1802–1997, for example, the average dividend-price ratio was 5.4% while the geometric average growth rate of prices was 1.6%. These numbers add to the geometric average return of 7.0%. Over the period 1871–1997 the average dividend-price ratio was 4.9% while the geometric average growth rate of prices was 2.1%, again adding to 7.0%. Similarly, Campbell and Shiller (2001) report that the average P/E ratio for S&P500 shares over the period 1872-2000 was 14.5. The reciprocal of this is 6.9%, consistent with average realized returns.

When valuation ratios and growth rates change over time, these formulas are no longer exactly correct. Campbell and Shiller (1988) and Vuolteenaho (2000) derive dynamic versions of the formulas that can be used in this context. Campbell and Shiller show, for example, that the log dividend-price ratio is a discounted sum of expected future discount rates, less a discounted sum of expected future dividend growth rates. In this note I will work with the simpler deterministic formulas.

II. Current market conditions

Current valuation ratios are wildly different from historical averages, reflecting the unprecedented bull market of the last 20 years, and particularly the late 1990's. The attached figure, taken from Campbell and Shiller (2001), illustrates this point. The bottom left panel shows the dividend-price ratio D/P in January of each year from 1872–2000. The long-term historical average is 4.7%, but D/P has fallen dramatically since 1982 to about 1.2% in January 2000 (and 1.4% today).

The dividend-price ratio may have fallen in part because of shifts in corporate financial policy. An increased tendency for firms to repurchase shares rather than pay dividends increases the growth rate of dividends per share, by shrinking the number of shares. Thus it increases G in the Gordon growth formula and reduces conventionally measured D/P. One way to correct for this is to add repurchases to conventional dividends. Recent estimates of this effect by Liang and Sharpe (1999) suggest that it may be an upward adjustment of 75 to 100 basis points, and more in some years. Of course, this is not nearly sufficient to explain the recent decline in D/P.

Alternatively, one can look at the price-earnings ratio. The top left panel of the figure shows P/E over the same period. This has been high in recent years, but there are a number of earlier peaks that are comparable. Close inspection of these peaks shows that they often occur in years such as 1992, 1934, and 1922 when recessions caused temporary drops in (previous-year) earnings. To smooth out this effect, Campbell and Shiller (2001), following Graham and Dodd (1934), advocate averaging earnings over 10 years. The price-averaged earnings ratio is illustrated in the top right panel of the figure. This peaked at 45 in January 2000; the previous peak was 28 in 1929. The decline in the S&P500 since January 2000 has only brought the ratio down to the mid-30's, still higher than any level seen before the late 1990's.

The final panel in the figure, on the bottom right, shows the ratio of current to 10-year average earnings. This ratio has been high in recent years, reflecting robust earnings growth during the 1990's, but it is not unprecedentedly high. The really unusual feature of the recent stock market is the level of prices, not the growth of earnings.

III. Implications for future returns

The implications of current valuations for future returns depend on whether the market has reached a new steady state, in which current valuations will persist, or whether these valuations are the result of some transitory phenomenon.

If current valuations represent a new steady state, then they imply a substantial decline in the equity returns that can be expected in the future. Using Campbell and Shiller's (2001) data, the unadjusted dividend-price ratio has declined by 3.3 percentage points from the historical average. Even adjusting for share repurchases, the decline is at least 2.3 percentage points. Assuming constant long-term growth of the economy, this would imply that the geometric average return on equity is no longer 7%, but 3.7% or at most 4.7%. Looking at the price-averaged earnings ratio, adjusting for the typical ratio of current to averaged earnings, gives an even lower estimate. Current earnings are normally 1.12 times averaged earnings; $1.12/35 = 0.032$, implying a 3.2% return forecast. These forecasts allow for only a very modest equity premium relative to the yield on long-term inflation-indexed bonds, currently about 3.5%, or the 3% safe real return assumed recently by the Trustees.

If current valuations are transitory, then it matters critically what happens to restore traditional valuation ratios. One possibility is that earnings and dividends are below their long-run trend levels; rapid earnings and dividend growth will restore traditional valuations without any declines in equity returns below historical levels. While this is always a possi-

bility, Campbell and Shiller (2001) show that it would be historically unprecedented. The US stock market has an extremely poor record of predicting future earnings and dividend growth. Historically stock prices have increased relative to earnings during decades of rapid earnings growth, such as the 1920's, 1960's, or 1990's, as if the stock market anticipates that rapid earnings growth will continue in the next decade. However there is no systematic tendency for a profitable decade to be followed by a second profitable decade; the 1920's, for example, were followed by the 1930's and the 1960's by the 1970's. Thus stock market optimism often fails to be justified by subsequent earnings growth.[3]

A second possibility is that stock prices will decline or stagnate until traditional valuations are restored. This has occurred at various times in the past after periods of unusually high stock prices, notably the 1900's and 1910's, the 1930's, and the 1970's. This would imply extremely low and perhaps even negative returns during the adjustment period, and then higher returns afterwards.

The unprecedented nature of recent stock market behavior makes it impossible to base forecasts on historical patterns alone. One must also form a view about what happened to drive stock prices up during the 1980's and particularly the 1990's. One view is that there has been a structural decline in the equity premium, driven either by the correction of mistaken perceptions of risk (aided perhaps by the work of economists on the equity premium puzzle), or by the reduction of barriers to participation and diversification by small investors.[4] Economists such as McGrattan and Prescott (2001) and Jagannathan, McGrattan, and Scherbina (2001) argue that the structural equity premium is now close to zero, consistent with theoretical models in which investors effectively share risks and have modest risk aversion, and consistent with the view that the US market has reached a new steady state.

An alternative view is that the equity premium has declined only temporarily, either because investors irrationally overreacted to positive fundamental news in the 1990's (Shiller 2000), or because the strong economy made investors more tolerant of risk.[5] On this view the equity premium will return to historical levels, implying extremely poor near-term returns and higher returns in the more distant future after traditional valuations have been restored.

It is too soon to tell which of these views is correct, and I believe it is sensible to put some weight on each of them. That is, I expect valuation ratios to return part way but not

[3]Vuolteenaho (2000) notes, however, that US corporations were unusually profitable in the late 1990's and that profitability has some predictive power for future earnings growth.

[4]Heaton and Lucas (1999) model barriers of this sort. It is hard to get large effects of increased participation on stock prices unless initial participation levels are extremely low. Furthermore, one must keep in mind that what matters for pricing is the wealth-weighted participation rate, that is, the probability that a randomly selected dollar of wealth is held by an individual who can participate in the market. This is higher than the equal-weighted participation rate, the probability that a randomly selected individual can participate.

[5]Campbell and Cochrane (1999) present a model in which investors judge their well-being by their consumption relative to a recent average of past aggregate consumption. In this model investors are more risk-tolerant when consumption grows rapidly and they have a "cushion of comfort" relative to their minimum expectations. The Campbell-Cochrane model fits past cyclical variations in the stock market, which will likely continue in the future, but it is hard to explain the extreme recent movements using this model.

fully to traditional levels.[6] A rough guess for the long term, after the adjustment process is complete, might be a geometric average equity return of 5% to 5.5% or an arithmetic average return of 6.5% to 7%.

If equity returns are indeed lower on average in the future, it is likely that short-term and long-term real interest rates will be somewhat higher. That is, the total return to the corporate capital stock is determined primarily by the production side of the economy and by national saving and international capital flows; the division of total return between riskier and safer assets is determined primarily by investor attitudes towards risk. Reduced risk aversion then reduces the equity premium both by driving down the equity return and by driving up the riskless interest rate. The yield on long-term inflation-indexed Treasury securities (TIPS) is about 3.5%, while short-term real interest rates have recently averaged about 3%. Thus 3% to 3.5% would be a reasonable guess for safe real interest rates in the future, implying a long-run average equity premium of 1.5% to 2.5% in geometric terms or about 3% to 4% in arithmetic terms.

Finally, I note that it is tricky to use these numbers appropriately in policy evaluation. Average equity returns should never be used in base-case calculations without showing alternative calculations to reflect the possibilities that realized returns will be higher or lower than average. These calculations should include an alternative in which equities underperform Treasury bills. Even if the probability of underperformance is small over a long holding period, it cannot be zero or the stock market would be offering an arbitrage opportunity or "free lunch". Equally important, the bad states of the world in which underperformance occurs are heavily weighted by risk-averse investors. Thus policy evaluation should use a broad range of returns to reflect the uncertainty about long-run stock market performance.

[6]This compromise view also implies that negative serial correlation, or mean-reversion, is likely to remain a characteristic of stock returns in the 21st Century.

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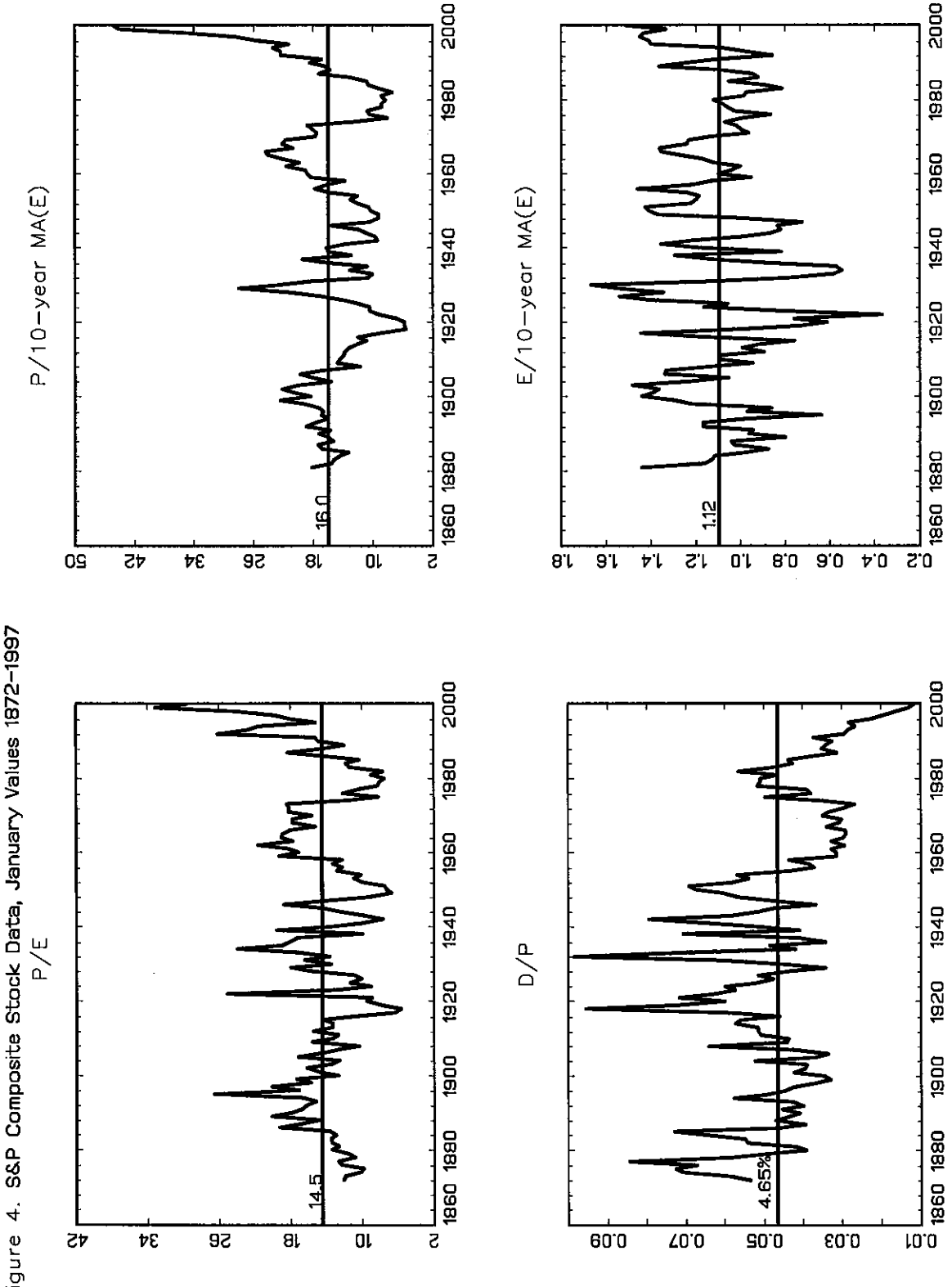

Figure 4. S&P Composite Stock Data, January Values 1872-1997

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Equity Premia as Low as Three Percent? Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Markets

JAMES CLAUS and JACOB THOMAS*

ABSTRACT

The returns earned by U.S. equities since 1926 exceed estimates derived from theory, from other periods and markets, and from surveys of institutional investors. Rather than examine historic experience, we estimate the equity premium from the discount rate that equates market valuations with prevailing expectations of future flows. The accounting flows we project are isomorphic to projected dividends but use more available information and narrow the range of reasonable growth rates. For each year between 1985 and 1998, we find that the equity premium is around three percent (or less) in the United States and five other markets.

THE EQUITY RISK PREMIUM LIES at the core of financial economics. Representing the excess of the expected return on the stock market over the risk-free rate, the equity premium is unobservable and has been estimated using different approaches and samples. The estimates most commonly cited in the academic literature are from Ibbotson Associates' annual reviews of the performance of various portfolios of U.S. stocks and bonds since 1926. Those estimates lie in the region of seven to nine percent per year, depending on the specific series examined. This historic evidence is objective and easy to interpret and has convinced many, especially academic financial economists, that the Ibbotson estimates are the best available proxies for the equity premium (Welch (1999)).[1] For discussion purposes, we use "eight percent"

* Barclays Global Investors and Columbia Business School, respectively. We thank I/B/E/S Inc. for their database of earnings estimates and Enrique Arzac and René Stulz for many helpful suggestions and discussions. Useful comments were received from anonymous referees, Bala Dharan, Darin Clay, Ilia Dichev, Ben Esty, Bob Hodrick, Irene Karamanou, S.P. Kothari, Jimmy Liew, Jing Liu, Jim McKeown, Karl Muller, Jim Ohlson, Stephen Penman, Huai Zhang, and workshop participants at AAA annual meetings (San Diego), Columbia University, Copenhagen Business School, University of Michigan, Michigan State University, University of North Carolina-Chapel Hill, Northern Arizona University, Ohio State University, Penn State University, Prudential Securities Quantitative Conference, Syracuse University, and University of Texas-Austin.

[1] The annualized distribution of monthly common stock returns over the 30-day T-bill rate has a mean of 9.12 percent and a standard deviation of 20.06 percent (from data in Table A-16, Ibbotson Associates (1999)). If these 73 observations are independent and identically distributed, the sample mean is a reasonable estimate for the equity premium, and the standard error of 2.35 percent associated with the sample mean allows an evaluation of other hypothesized values of the equity premium.

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and "the Ibbotson estimate" interchangeably to represent the historic mean of excess returns earned by U.S. equities since 1926. (Unless noted otherwise, all amounts and rates are stated in nominal, not real, terms.)

Our objective is to show empirically that eight percent is too high an estimate for the equity premium in recent years. Rather than examine observed returns, we estimate for each year since 1985 the discount rate that equates U.S. stock market valuations with the present value of prevailing forecasts of future flows. Subtracting 10-year risk-free rates from these estimated discount rates suggests that the equity premium is only about three percent.[2] An examination of five other large stock markets (Canada, France, Germany, Japan, and the United Kingdom) provides similar results. Despite substantial variation in the underlying fundamentals across markets and over time, observing that every one of our 69 country-year estimates lies well below eight percent suggests that the Ibbotson estimate is too high for our sample period. Examination of various diagnostics (such as implied future profitability) confirms that the projections required to support an eight percent equity premium are unreasonable and inconsistent with past experience.

Some features of our study should be emphasized at the outset. As we only seek to establish a reasonable upper bound for the equity premium, we select long-term growth assumptions that exceed past experience and do not adjust for optimism in the analyst forecasts used.[3] Also, we use the simplest structure necessary to conduct our analysis. Our estimates refer to a long-term premium expected to hold over all future years (whereas historical estimates measure one-period premia), and we assume that the premium is constant over those future years (we do incorporate anticipated variation in risk-free rates). Finally, each annual estimate is conditional on the information available in that year; we do not consider an unconditional equity premium toward which those conditional premia might gravitate in the long run.

We are not the first to question the validity of the Ibbotson estimate. Mehra and Prescott (1985) initiated a body of theoretical work that has examined the so-called "equity premium puzzle." Their model indicates that the variance–covariance matrix of aggregate consumption and returns on stocks and bonds, when combined with reasonable risk-aversion parameters, implies equity premium estimates that are less than one percent. Despite subsequent efforts to bridge this gap (e.g., Abel (1999)), concerns remain about the validity of the Ibbotson estimate (see Kocherlakota (1996), Cochrane (1997), and Siegel and Thaler (1997) for summaries).

[2] Gebhardt, Lee, and Swaminathan (forthcoming) find similar results when estimating firm-specific discount rates, rather than the market-level discount rates considered in this paper.

[3] As described later, analyst optimism has declined systematically over time and a simple adjustment for mean bias is inappropriate. Bayesian adjustments to control for observed analyst optimism are not considered because we focus on an upper bound. In general, we do not use more complex econometric techniques and data refinements that are available to get sharper point estimates (e.g., Mayfield (1999), Vuolteenaho (1999), and Ang and Liu (2000)).

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Surveys of institutional investors also suggest an equity premium substantially below eight percent (e.g., Burr (1998)), and there are indications that this belief has been held for many years (e.g., Benore (1983)).[4] Also, the weighted average cost of capital used in discounted cash flow valuations provided in analysts' research reports usually implies an equity premium below five percent. Current share prices appear systematically overpriced if an eight percent equity premium is used on reasonable projections of future flows. This overpricing is more evident when examining mature firms, where there is less potential for disagreement about growth opportunities.

To identify possible reasons why the Ibbotson estimate might overstate the equity premium in recent years, apply the Campbell (1991) decomposition of observed returns (in excess of the expected risk-free rate) for the market portfolio. The four components are: (1) the expected equity premium for that period; (2) news about the equity premium for future periods; (3) news about current and future period real dividend growth; and (4) news about the real risk-free rate for current and future periods. Here, news represents changes in expectations between the beginning and end of the current period (for current period dividend growth and risk-free rates, it represents the unexpected portion of observed values). Summing up both sides of this relation for each year since 1926 indicates that the average excess return observed would exceed the equity premium today if: (1) conditional one-year-ahead equity premia have declined; (2) the conditional long-term equity premium anticipated for future years has declined; (3) news about real dividend growth was positive on average; or (4) the expected real risk-free rate has declined.

The first and second reasons for why the Ibbotson estimate overstates the current equity premium highlight the potential pitfalls of estimating equity premia from observed returns. Holding aside news about dividends and risk-free rates, valuations would exceed expectations if the equity premium has declined (since present values increase when expected rates of return decline). That is, unexpected changes in the equity premium cause historical equity premium estimates to move in the opposite direction. Blanchard (1993) concludes that the equity premium has declined since 1926 to two or three percent by the early 1990s, and speculates that this decline is caused by a simultaneous decline in expected real rates of return on stocks and an increase in expected real risk-free rates. (This increase in expected real risk-free rates is another puzzle, but that puzzle is beyond the scope of this paper.) The remarkable run-up in stock prices during the 1990s, both domestically as well as internationally, is also consistent with a recent decline

[4] While many argue for an equity premium between two and three percent (e.g., Bogle (1999, p. 76)), some suggest that the premium is currently close to zero (e.g., Glassman and Hassett (1998), and Wien (1998)). Surveys of *individual* investors, on the other hand, suggest equity premia even higher than the Ibbotson estimate. For example, the *New York Times* (October 10, 1997, page 1, "High hopes of mutual fund investors"), reported an equity premium in excess of 16 percent from a telephone survey conducted by Montgomery Asset Management.

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in the equity premium. Stulz (1999) argues that increased globalization has caused equity premia to decline in all markets.

Examination of historic evidence over other periods and markets suggests that the U.S. experience since 1926 is unusual. Siegel (1992) finds that the excess of observed annual returns for NYSE stocks over short-term government bonds is 0.6, 3.5, and 5.9 percent over the periods 1802 to 1870, 1871 to 1925, and 1926 to 1990, respectively. Jorion and Goetzmann (1999) examine the evidence for 39 equity markets going back to the 1920s, and conclude that the high equity premium observed in the United States appears to be the exception rather than the rule. Perhaps some stock markets collapsed and those markets that survived, like the U.S. exchanges, exhibit better performance than expected (see Brown, Goetzmann, and Ross (1995)). This evidence is consistent with the third reason for the high Ibbotson premium: since 1926, news about real dividend growth for U.S. stocks has been positive on average.

Partially in response to these limitations of inferring equity premia from observed returns, financial economists have considered forward-looking approaches based on projected dividends.[5] Informally, expected rates of return on the market equal the forward dividend yield plus expected growth in dividends (this dividend growth model is discussed in Section I). While dividend yields are easily measured, expected dividend growth in perpetuity is harder to identify. Proxies used for expected dividend growth include observed growth in earnings, dividends, or economy-wide aggregates (e.g., Fama and French (2000)). Unfortunately, the dividend growth rate that can be sustained in perpetuity is a hypothetical rate that is not necessarily anchored in any observable series, leaving considerable room for disagreement (see the Appendix for explanation).

We use a different forward-looking approach, labeled the abnormal earnings (or residual income) model, to mitigate problems associated with the dividend growth model.[6] Recognizing that dividends equal earnings less changes in accounting (or book) values of equity allows the stream of projected dividends to be replaced by the current book value of equity plus a function of future accounting earnings (details follow in Section I). While book values feature prominently in the model, the inclusion of future abnormal earnings makes it isomorphic to the dividend discount model. Relative to the dividend growth model, this approach makes better use of currently

[5] A related approach is to run predictive regressions of market returns or equity premium on dividend yields and other variables (e.g., Campbell and Shiller (1988)). We do not consider that approach because the declining dividend yields in recent years have caused predicted equity premium to turn negative (e.g., Welch (1999)).

[6] The approach appears to have been discovered independently by a number of economists and accountants over the years. Preinreich (1938) and Edwards and Bell (1961) are two early cites. More recently, a large body of analytical and empirical work has utilized this insight (e.g., Penman (1999)). Examples of empirical investigations include market myopia (Abarbanell and Bernard (1999)), explaining cross-sectional variation in returns (Liu and Thomas (2000)), and stock picking (Frankel and Lee (1998a, 1998b)).

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available information to reduce the importance of assumed growth rates, and it narrows the range of allowable growth rates by focusing on growth in rents, rather than dividend growth.

If the equity premium is as low as our estimates suggest, required rates of return (used for capital budgeting, regulated industries, and investment decisions) based on the Ibbotson estimate are severely overstated. Second, a smaller equity premium reduces the importance of estimating beta accurately (because required rates of return become less sensitive to variation in beta) and increases the magnitude of beta changes required to explain abnormal returns observed for certain market anomalies. Finally, reducing substantially the magnitude of the equity premium puzzle to be explained might reinvigorate theory-based studies.

In Section I we develop the abnormal earnings approach used in this paper and compare it with the dividend growth model. Section II contains a description of the sample and methodology. The equity premium estimates for the United States are reported in Section III, and those for the five other markets are provided in Section IV. To confirm that our estimates are robust, we conducted extensive sensitivity analyses, which we believe represent an important contribution of our research effort. A summary of that investigation is reported in Section V (details are provided in Claus and Thomas (1999a)) and Section VI concludes.

I. Dividend Growth and Abnormal Earnings Models

The Gordon (1962) dividend growth model is described in equation (1). This relation implies that the expected rate of return on the stock market (k^*) equals the forward dividend yield (d_1/p_0) plus the dividend growth rate in perpetuity (g) expected for the market.

$$p_0 = \frac{d_1}{k^* - g} \Rightarrow k^* = \frac{d_1}{p_0} + g \tag{1}$$

where

p_0 = current price, at the end of year 0,
d_t = dividends expected at the end of future year t,
k^* = expected rate of return on the market, derived from the dividend growth model, and
g = expected dividend growth rate, in perpetuity.

The Gordon growth model is a special case of the general Williams (1938) dividend discount model, detailed in equation (2), where dividend growth is constrained to equal g each year.

$$p_0 = \frac{d_1}{(1+k^*)} + \frac{d_2}{(1+k^*)^2} + \frac{d_3}{(1+k^*)^3} + \ldots \tag{2}$$

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Research using the dividend growth model has often assumed that g equals forecasted earnings growth rates obtained from sell-side equity analysts, who provide earnings forecasts along with their buy/sell recommendations. These forecasts refer to earnings growth over the next "cycle," which is commonly interpreted to represent the next five years. Consequently, we refer to this earnings growth forecast as g_5. While most studies using g_5 as a proxy for g have focused on the U.S. market alone (e.g., Brigham, Shome, and Vinson (1985)), some have examined other major equity markets also (e.g., Khorana, Moyer, and Patel (1997)). Estimates of the equity premium based on the assumption that g equals g_5 are similar in magnitude to the Ibbotson estimate derived from historical data. For example, Moyer and Patel (1997) estimate the equity premium each year over their 11-year sample period (1985 to 1995) and generate a mean estimate of 9.38 (6.96) percent relative to the 1-year (30-year) risk-free rate.

However, others have balked at using g_5 as a proxy for g (e.g., Malkiel (1996), Cornell (1999)) because it appears unreasonably high at an intuitive level, and have stepped down assumed growth rates. Forecasted values of g_5 for the United States over our sample period, which are close to 12 percent in all years, exceed nominal growth in S&P earnings, which has been only 6.6 percent since the 1920s (*Wall Street Journal*, June 16, 1997, "As stocks trample price measures, analysts stretch to justify buying"). Also, the real growth rate implied by the nominal 12 percent earnings growth rate exceeds both forecast and realized growth in GDP (since 1970, forecasts of expected real growth in GDP have averaged 2.71 percent, and realized real growth has averaged 2.81 percent).

While we show that g_5 is systematically optimistic relative to realized earnings, it is difficult to infer reliably the level of that optimism from the relatively short time-series of forecast errors available (reliable data on analyst forecasts go back only about 15 years). Moreover, the incentives for analysts to make optimistic forecasts vary across firms and over time. For example, the literature on U.S. analysts' forecasts suggests that while analysts tended to make optimistic forecasts early in our sample period (to curry favor with management), more recently, management has tended to guide near-term analyst forecasts downward to be able to meet or beat them when announcing earnings.[7] Even if unbiased estimates of near-term earnings growth (g_5) were available, the Appendix describes why those estimates as well as observed growth rates are conceptually different from g, the hypothetical dividend growth that can be sustained in perpetuity.

[7] Results reported in Table VI offer clear evidence of such a decline in optimism for all horizons. Bagnoli, Beneish, and Watts (1999) document how recent analyst forecasts are systematically below reported earnings for their sample, and also below "whisper" forecasts that are generally viewed as representing the market's true earnings expectations. Matsumoto (1999) offers evidence in support of management guiding analyst forecasts downward, and also investigates factors that explain cross-sectional variation in this propensity to guide analysts.

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The abnormal earnings model is an alternative that mitigates many of the problems noted above. Expected dividends can be related to forecasted earnings using equation (3) below, and that relation allows a conversion of the discounted dividends relation in equation (2) to the abnormal earnings relation in equation (4).

$$d_t = e_t - (bv_t - bv_{t-1}) \tag{3}$$

$$p_0 = bv_0 + \frac{ae_1}{(1+k)} + \frac{ae_2}{(1+k)^2} + \frac{ae_3}{(1+k)^3} + \ldots, \tag{4}$$

where

e_t = earnings forecast for year t,
bv_t = expected book (or accounting) value of equity at the end of year t,
$ae_t = e_t - k(bv_{t-1})$ = expected abnormal earnings for year t, or forecast accounting earnings less a charge for the cost of equity, and
k = expected rate of return on the market portfolio, derived from the abnormal earnings model.

Equation (3), also known as the "clean surplus" relation, requires that all items affecting the book value of equity (other than transactions with shareholders, such as dividends and share repurchases/issues) be included in earnings. Under U.S. accounting rules, almost all transactions satisfy the clean-surplus assumption. An examination of the few transactions that do not satisfy this relation suggests that these violations occur ex post, and are not anticipated in analysts' earnings forecasts (e.g., Frankel and Lee (1998b)). Since we construct future book values using equation (3), by adding forecast income to and subtracting forecast dividends from beginning book values, clean surplus is maintained and the dividend and abnormal earnings relations in equations (2) and (4) are isomorphic.

Equation (4) shows that the current stock price equals the current book value of equity plus the present value of future expected abnormal earnings. Abnormal earnings, a proxy for economic profits or rents, adjusts reported earnings by deducting a charge for equity capital. Note that the market discount rates estimated from the abnormal earnings and dividend growth approaches are labeled differently: k and k^*. Also, the standard transversality conditions apply to both models: in the limit as t approaches infinity, the present value of future price, p_t (difference between price and book value, $p_t - bv_t$) must tend to zero in equation (2) (in equation (4)).

Financial economists have expressed concerns about accounting earnings deviating from "true" earnings (and book values of equity deviating from market values), in the sense that accounting numbers are noisy and easily manipulated. However, the equivalence between equations (2) and (4) is not impaired by differences between accounting and economic numbers, nor is it affected by the latitude available within accounting rules to report different

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accounting numbers. As long as forecasted earnings satisfy the clean surplus relation in equation (3) in terms of expectations, equation (4) is simply an algebraic restatement of equation (2), subject to the respective transversality conditions mentioned above.

Since the I/B/E/S database we use does not provide analysts' earnings forecasts beyond year +5, we assume that abnormal earnings grow at a constant rate (g_{ae}) after year +5, to incorporate dates past that horizon. Equation (4) is thus adapted as follows.

$$p_0 = bv_0 + \frac{ae_1}{(1+k)} + \frac{ae_2}{(1+k)^2} + \frac{ae_3}{(1+k)^3} + \frac{ae_4}{(1+k)^4} + \frac{ae_4}{(1+k)^5} + \left[\frac{ae_5(1+g_{ae})}{(k-g_{ae})(1+k)^5}\right]. \tag{5}$$

The last, bracketed term is a terminal value that captures the present value of abnormal earnings after year +5. The terms before are derived from accounting statements (bv_0) and analyst forecasts (e_1 to e_5). Note that there are three separate growth rates in this paper and the different growth rates refer to different streams and periods and arise from different sources. The rate g refers to dividend growth in perpetuity and is assumed by the researcher; g_5 refers to growth in accounting earnings over the first five years and is provided by financial analysts; and g_{ae} refers to abnormal earnings growth past year +5 and is assumed by the researcher.

Whereas expected rates of return are typically viewed as being stochastic (Samuelson (1965)), k^* and k in equations (1) and (5) are nonstochastic discount rates. Barring a few recent exceptions (e.g., Ang and Liu (2000) and Vuolteenaho (1999)), the literature has assumed that expected rates of return can be approximated by discount rates. We make that assumption too. While equation (1) is designed to only reflect a flat k^*, equation (2) can be restated to incorporate predictable variation over time in discount rates. Similarly, equation (5) can be restated to incorporate nonflat discount rates, as shown in Claus and Thomas (1999a). We consider the case when the equity premium is assumed to remain flat but discount rates vary over future periods based on the term-structure of risk-free rates. This restated version of equation (5) is

$$p_0 = bv_0 + \sum_{t=1}^{\infty}\left[\frac{ae_t}{\prod_{s=1}^{t}(1+r_{fs}+rp)}\right], \tag{5a}$$

where

r_{fs} = forward one-year risk-free rate for year s,
rp = equity risk premium, assumed constant over all future years,
ae_t = expected abnormal earnings for year t, equals $e_t - bv_{t-1}(r_{ft} + rp)$ for years +1 through +5, and equals $ae_5(1 + g_{ae})^{t-5}$, from year +6 on.

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While the abnormal earnings stream in equation (4) is equivalent to the corresponding dividend stream in equation (2), the abnormal earnings relation in equation (5) (and equation (5a)) offers the following advantages over the dividend growth model in equation (1). First, a substantial fraction of the "value profile" for the abnormal earnings model in equation (5) is fixed by numbers that are currently available and do not need to be assumed by the researcher (current book value and abnormal earnings for years +1 through +5). Value profile is a representation of the fraction of total value captured by each future year's flows. In contrast, the entire value profile for the dividend growth model is affected by the assumed growth rate, g. Since the fraction of value determined by assumed growth rates is lower for the abnormal earnings approach, those risk premium estimates are more reliable.

Second, in contrast to the potential for disagreement about a reasonable range for g, the rate at which rents can grow in perpetuity after year +5, g_{ae}, is less abstract and easier to gauge using economic intuition. For example, to obtain equity premia around 8 percent, rents at the market level would have to grow forever at about 15 percent, on average. It is unlikely that aggregate rents to U.S. equity holders would grow at such high rates in perpetuity because of factors such as antitrust actions, global competition, and pressure from other stakeholders. The historical evidence (e.g., Myers (1999)) is also at odds with such high growth rates in abnormal earnings.

Third, future streams for a number of value-relevant indicators, such as price-to-book ratios (P/B), price-to-earnings ratios (P/E), and accounting return on equity (*roe*), can also be projected under the abnormal earnings approach. This allows one to paint a more complete picture of the future for different assumed growth rates. Analysis of the levels of future P/B and profitability (excess of *roe* over k) implied by growth rates required to obtain equity premium estimates around eight percent are also inconsistent with past experience.

II. Data and Methodology

I/B/E/S provides the consensus of all available individual forecasts as of the middle (the Thursday following the second Friday) of each month. Forecasts and prices should be gathered soon after the prior year-end, as soon as equity book values (bv_0) are available. Rather than collect forecasts at different points in the year, depending on the fiscal year-end of each firm, we opted to collect data as of the same month each year for all firms to ensure that the risk-free rate is the same across each annual sample. Since most firms have December year-ends, and book values of equity can be obtained from the balance sheets that are required to be filed with the SEC within 90 days of the fiscal year-end, we collect forecasts as of April each year.[8] For

[8] For the few firm-years not filing within this 90-day deadline, the book value of equity can be inferred by the market by adding (subtracting) fourth quarter earnings (dividends) from the third quarter book value of equity.

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firms with fiscal year-ends other than December, this procedure creates a slight upward bias in estimated equity premium, since the stock prices used (as of April) are on average higher than those near the prior year's fiscal year-end, when bv_0 was released. In addition to earnings forecasts, I/B/E/S also provides data for actual earnings per share, dividends per share, share prices, and the number of outstanding shares. Equity book values are collected from COMPUSTAT's Industrial Annual, Research, and Full Coverage Annual Files, for years up to and including 1997.

The sample includes firms with I/B/E/S earnings forecasts for years +1 and +2 (e_1 and e_2) and a five-year growth forecast (g_5) as well as share prices and shares outstanding as of the I/B/E/S cut off date each April. We also require nonmissing data for the prior year's book value, earnings, and dividends. Explicit forecasts for years +3, +4, and +5 are often unavailable, and are generated by projecting the growth rate g_5 on the prior year's earnings forecast: $e_t = e_{t-1}(1 + g_5)$.[9]

Earlier years in the I/B/E/S database, before 1985, were dropped because they provided too few firms with complete data to represent the overall market. From 1985 on, the number of firms with available data increases substantially. As shown in column 1 of Table I, the number of sample firms increases from 1,559 in 1985 to 3,673 in 1998. Comparison with the total number of firms and market capitalization of all firms on NYSE, AMEX, and Nasdaq each April indicates that, although our sample represents only about 30 percent of all such firms, it represents 90 percent or more of the total market capitalization. Overall, we believe our sample is fairly representative of the value-weighted market, and refer to it as "the market" hereafter.

Firm-level data are aggregated each year to generate market-level earnings, book values, dividends, and capitalization. Actual data for year 0 (the full fiscal year preceding each April when forecasts were collected) is provided in columns 2 through 6 of Table I. Forecasted and projected earnings for years +1 through +5 are reported in columns 7 through 11.

Table I reveals an interesting finding relating to dividend payouts: the ratio of market dividends to earnings is around 50 percent in most years (with a noticeable decline toward the end of the sample period).[10] We use this 50 percent payout ratio to project future dividends from earnings fore-

[9] If any of the explicit earnings forecasts for years +2, +3, +4, or +5 were negative, they were not used to project earnings for subsequent years. For about five percent of our sample, explicit earnings forecasts are available for all five years and do not need to be inferred using g_5. That subsample was investigated to confirm that projections based on five-year growth rates are unbiased proxies for the explicit forecasts for those years.

[10] Although this statistic is well known to macroeconomists, it is higher than average firm-level dividend payouts. Note, however, that aggregate earnings include many loss firms, especially in the early 1990s, when earnings were depressed because of write-offs and accounting changes. This results in a higher aggregate dividend payout than the average firm-level payout ratio, which is computed over profitable firms only (the payout ratio is meaningless for loss firms). Also, since the aggregate payout ratio is a value-weighted average dividend payout, it is more representative of large firms, which tend to have higher dividend payouts than small firms.

Table I

Market Capitalization, Book Values, Dividends, and Actual and Forecast Earnings for U.S. Stocks (1985 to 1998)

The market consists of firms on the I/B/E/S Summary files with forecasts for years +1, +2, and a five-year earnings growth estimate (g_5) as of April each year, and actual earnings per share, dividends per share, number of shares outstanding and share prices as of the end of the prior fiscal year (year 0). Book values of equity for year 0 are obtained from COMPUSTAT. When missing on the I/B/E/S files, forecasted earnings per share for years +3, +4, and +5 are determined by applying g_5, the forecasted five-year growth rate, to year +2 forecasted earnings. All per share numbers are multiplied by the number of shares outstanding to get amounts at the firm level, and these are added across firms to get amounts at the market level each year. All amounts, except for dividend payout, are in millions of dollars.

Forecast as of April	Number of Firms	Actual Values for Year 0					Forecast Earnings for Years +1 to +5				
		Earnings	Dividends	Payout	Book Value	Market Value	Year +1	Year +2	Year +3	Year +4	Year +5
	1		3			6	7	8	9	10	11
1985	1,559	154,858	71,134	46%	1,191,869	1,747,133	180,945	205,294	228,208	254,181	283,706
1986	1,613	155,201	73,857	48%	1,214,454	2,284,245	178,024	203,677	226,018	251,313	280,035
1987	1,774	146,277	81,250	56%	1,323,899	2,640,743	186,319	220,178	244,174	271,432	302,529
1988	1,735	167,676	86,237	51%	1,430,672	2,615,857	222,497	246,347	273,204	303,642	338,262
1989	1,809	229,070	97,814	43%	1,541,231	2,858,585	261,278	284,616	315,204	349,721	388,776
1990	1,889	228,216	107,316	47%	1,636,069	3,143,879	257,657	295,321	328,803	366,798	410,028
1991	1,939	218,699	108,786	50%	1,775,199	3,660,296	241,760	294,262	328,513	367,521	412,073
1992	2,106	202,275	113,962	56%	1,911,383	4,001,756	252,109	308,567	344,742	386,098	433,552
1993	2,386	247,988	127,440	51%	2,140,668	4,918,359	295,862	356,086	397,969	445,840	501,081
1994	2,784	290,081	129,186	45%	2,168,446	5,282,046	339,694	402,689	450,559	505,315	568,179
1995	2,965	365,079	147,575	40%	2,670,725	6,289,760	444,593	518,600	579,954	650,120	730,648
1996	3,360	446,663	175,623	39%	3,182,952	8,207,274	512,921	588,001	659,732	742,244	837,577
1997	3,797	547,395	201,017	37%	3,679,110	10,198,036	614,932	709,087	800,129	905,787	1,029,061
1998	3,673	526,080	178,896	34%	3,412,303	12,908,495	577,297	682,524	775,707	884,529	1,012,294

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casts, as well as to project future book values (using equation (3)). The validity of this assumption is not critical; however, varying the payout ratio between 25 and 75 percent has little impact on the estimated discount rate (results available upon request).

Both short- and long-term risk-free rates have been used in studies that estimate discount rates from flows that extend over many future periods. While one-month or one-year rates are appropriate when inferring the equity premium from historic returns (observed return less risk-free yield for that period), for studies based on forecasted flows, the maturity of risk-free rates used should match that of the future flows (Ibbotson Associates (1999)). Although we allow for expected variation in risk-free rates when estimating the risk premium, using equation (5a), we find almost identical results using a constant risk-free rate in equation (5) equal to the long-term rate. In essence, the shape of the yield curves over our sample period is such that the forward rates settle rather quickly at the long-term rate, and the impact of discounting flows from earlier years in the profile at rates lower than the long-term rate is negligible. For the sensitivity analyses, we find it convenient to use the constant rate structure of equation (5), rather than the varying rate structure of equation (5a). We selected the 10-year risk-free rate for the constant risk-free rate because it is the longest maturity for which data could be obtained for all country-years in our sample. To allow comparisons with other studies that use 30-year risk-free rates, we note that the mean 30-year risk-free rate in April for each year of our U.S. sample period is 31 basis points higher than the mean 10-year risk-free rate we use.

For years beyond year +5, abnormal earnings are assumed to grow at the expected inflation rate, g_{ae}. As explained in the Appendix, the expected nominal inflation rate is higher than values of g_{ae} assumed in the literature, and is an upper bound for expected growth in abnormal earnings. We derive the expected inflation rate from the risk-free rate, based on the assumption that the real risk-free rate is approximately three percent.[11] Since we recognize that this assumption is only an educated guess, we consider in Section V.D other values of g_{ae} also. Fortunately, our estimated risk premium is relatively robust to variation in the assumed growth rate, g_{ae}, since a lower proportion of current market value is affected by g_{ae} in equations (5) and (5a), relative to the impact of g in equation (1).

III. Results

Since k appears in both the numerators (ae_t is a function of k) and denominators of the terms on the right-hand side of equation (5), the resulting

[11] The observed yields on recently issued inflation-indexed government bonds support this assumption. Although estimates of the real risk-free rate vary through time, and have historically been lower than three percent, more recently, the excess of the long-term risk-free rate over inflation forecasts has risen to three or four percent (e.g., Blanchard (1993), and discussion by Siegel).

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equation is a polynomial in k with many possible roots. Empirically, however, only one root is real and positive (see Botosan (1997)). We search manually for the value of k that satisfies the relation each year, with the first iteration being close to the risk-free rate. The equity risk premium estimate (rp) that satisfies the valuation relation in equation (5a) is also estimated iteratively.

Table II provides the results of estimating rp, k, and k^*. The annual estimates for rp (in column 13) lie generally between three and four percent and are much lower than the historic Ibbotson estimate. Also, there is little variation over time: each annual estimate is remarkably close to the mean value of 3.39 percent. The annual estimates for k (in column 9) vary between a high of 14.38 percent in 1985 and a low of 8.15 percent in 1998. The corresponding risk-free rates (10-year Government T-bond yields) reported in column 8 vary with the estimated ks, between 11.43 percent in 1985 and 5.64 percent in 1998. As a result, the estimated equity premia (in column 11), equal to k less r_f, exhibit little variation around the time-series mean of 3.40 percent.

While the equation (5a) equity premium estimates (rp) derived from non-flat risk-free rates are in concept more accurate than those derived by subtracting 10-year risk-free rates from the flat k estimated from equation (5), the numbers reported in column 11 are very similar to those reported in column 13. We only consider the equation (5) estimates hereafter because (a) the magnitudes of the discount rates and their relation to risk-free rates are more transparent for the risk premium estimates based on constant risk-free rates, and (b) forward one-year rates for different maturities are not available for the other five markets,.

To understand better the relative magnitudes of the terms in equation (5), we report in the first seven columns of Table II the fraction of market values represented by each term. The fraction represented by book value (column 1) has generally declined over our sample period, from 68.2 percent in 1985 to 26.4 percent in 1998. To compensate, the fraction represented by terminal value (column 7) has increased from 26.6 percent in 1985 to 60 percent in 1998. The fraction represented by abnormal earnings for years +1 to +5 has also increased.

Column 10 of Table II contains our estimates for k^*, the market discount rate based on the dividend growth model described by equation (1), when dividends are assumed to grow in perpetuity at the five-year growth in earnings forecast (g_5). Since g_5 is not available at the aggregate level, we use the forecast growth in aggregate earnings from year +4 to +5 (see column 16 of Table V) to identify g_5 at the market level. To maintain consistency with prior research using the dividend growth model, we estimate d_1 by applying the earnings growth forecast for year 1 on prior year dividends ($d_1 = d_0 * e_1/e_0$). Our estimates for k^* are almost identical to those reported by Moyer and Patel (1997).[12] Note that these estimates of k^* are much larger than the

[12] Similar results are expected because the underlying data is taken from the same source, with minor differences in samples and procedures; for example, they use the S&P 500 index whereas we use all firms with available data.

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Table II

Implied Expected Rate of Return on the Market (k and k^*) and Equity Risk Premium (rp and $k - r_f$) for U.S. Stocks (1985 to 1998)

The market is an aggregate of firms on the I/B/E/S Summary files with forecasts for years +1, +2, and a five-year earnings growth estimate (g_5) as of April each year, and actual earnings, dividends, number of shares outstanding and prices as of the end of the prior full fiscal year (year 0). Book values of equity for year 0 (bv_0) are obtained from COMPUSTAT. When missing, forecasted earnings for years +3, +4, and +5 are determined by applying g_5, the forecasted five-year growth rate, to year +2 forecasted earnings. The implied discount rate that satisfies the valuation relation in equation (5) below is k. Abnormal earnings (ae_t) equal reported earnings less a charge for the cost of equity (= beginning book value of equity * k). Assuming that 50 percent of earnings are retained allows the estimation of future book values from current book values and forecast earnings. The terminal value represents all abnormal earnings beyond year +5. Those abnormal earnings are assumed to grow at a constant rate, g_{ae}, which is assumed to equal the expected inflation rate, and is set equal to the current 10-year risk-free rate less 3 percent. The expected rate of return on the market is also estimated using equation (1), and is labeled k^*. Equation (1) is derived from the dividend growth model, and dividend growth in perpetuity, g, is assumed to equal the five-year earnings growth rate, g_5. Subtracting r_f from the discount rates k and k^* generates equity premium estimates. The equity premium (rp) is also estimated using equation (5a), which is based on the same information used in equation (5), except that the constant discount rate k is replaced by forward one-year risk-free rates at different maturities (r_{fs}) plus a constant risk premium (rp). All amounts, except for rates of return, are in millions of dollars.

$$k^* = \frac{d_1}{p_0} + g \tag{1}$$

$$p_0 = bv_0 + \frac{ae_1}{(1+k)} + \frac{ae_2}{(1+k)^2} + \frac{ae_3}{(1+k)^3} + \frac{ae_4}{(1+k)^4} + \frac{ae_5}{(1+k)^5} + \left[\frac{ae_5(1+g_{ae})}{(k-g_{ae})(1+k)^5}\right] \tag{5}$$

$$p_0 = bv_0 + \sum_{t=1}^{\infty}\left[\frac{ae_t}{\prod_{s=1}^{t}(1+r_{fs}+rp)}\right] \tag{5a}$$

Forecast as of April	Book Value as Percent of Market Value	Percent of Market Value Represented by Present Value of											
		ae_1	ae_2	ae_3	ae_4	ae_5	Terminal Value	10-year r_f	k from (5)	k^* from (1)	$k - r_f$	$k^* - r_f$	rp from (5a)
	1			4			7		9	10			13
1985	68.2%	0.5%	0.9%	1.1%	1.3%	1.5%	26.6%	11.43%	14.38%	16.14%	2.95%	4.71%	2.88%
1986	53.2%	1.6%	2.0%	2.1%	2.3%	2.4%	36.3%	7.30%	11.28%	14.90%	3.98%	7.60%	4.03%
1987	50.1%	1.3%	1.9%	2.1%	2.2%	2.3%	40.0%	8.02%	11.12%	15.08%	3.10%	7.06%	3.25%
1988	54.7%	1.7%	1.8%	1.9%	2.0%	2.2%	35.7%	8.72%	12.15%	15.52%	3.43%	6.80%	3.58%
1989	53.9%	2.0%	2.0%	2.0%	2.1%	2.2%	35.7%	9.18%	12.75%	14.85%	3.57%	5.67%	3.54%
1990	52.0%	1.6%	2.0%	2.1%	2.2%	2.3%	37.8%	8.79%	12.33%	15.41%	3.54%	6.62%	3.56%
1991	48.5%	1.1%	1.9%	2.0%	2.2%	2.4%	41.8%	8.04%	11.05%	15.16%	3.01%	7.12%	2.96%
1992	47.8%	1.1%	1.9%	2.1%	2.3%	2.5%	42.4%	7.48%	10.57%	15.55%	3.09%	8.07%	3.06%
1993	43.5%	1.7%	2.3%	2.5%	2.7%	2.9%	44.4%	5.97%	9.62%	15.12%	3.65%	9.15%	3.76%
1994	41.1%	2.1%	2.6%	2.8%	2.9%	3.1%	45.5%	5.97%	10.03%	15.02%	4.06%	9.05%	3.53%
1995	42.5%	2.1%	2.6%	2.7%	2.8%	3.0%	44.3%	7.06%	11.03%	14.96%	3.97%	7.90%	4.02%
1996	38.8%	2.2%	2.5%	2.6%	2.8%	3.0%	48.2%	6.51%	9.96%	14.96%	3.45%	8.45%	3.50%
1997	36.1%	2.2%	2.5%	2.6%	2.8%	3.0%	50.8%	6.89%	10.12%	13.88%	3.23%	6.99%	3.25%
1998	26.4%	2.1%	2.5%	2.7%	3.0%	3.2%	60.0%	5.64%	8.15%	13.21%	2.51%	7.57%	2.53%
Mean								7.64%	11.04%	14.98%	3.40%	7.34%	3.39%

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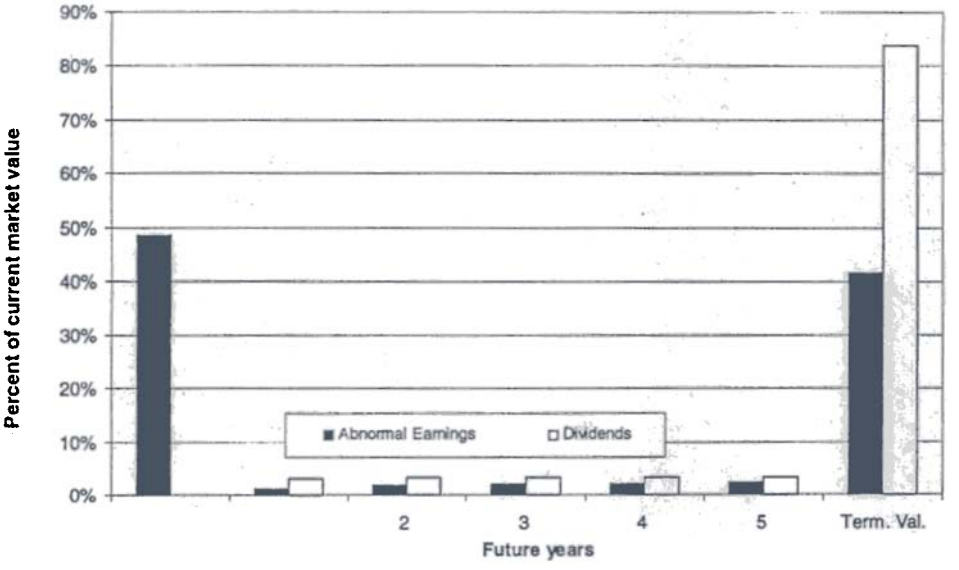

Figure 1. Comparison of value profile for abnormal earnings versus dividends, for abnormal earnings approach for U.S. stocks as of April, 1991. Based on the data in Table II, for the abnormal earnings approach described by equation (5), abnormal earnings are assumed to grow at 5.04 percent, the anticipated inflation rate, past year +5, and the resulting market discount rate (k) is 11.05 percent. For the abnormal earnings profile, the fractions represented by book value, abnormal earnings in years +1 through +5, and the terminal value are shown by the solid columns. For the dividend profile corresponding to those abnormal earnings projections, the fractions of current market capitalization that are represented by dividends in years +1 through +5 and the terminal value are shown by the hollow columns.

corresponding values of k, and the implied equity premium estimates reported in column 12 ($k^* - r_f$) are about twice those in column 11 ($k - r_f$). The mean equity premium of 7.34 percent in column 12 of Table II is approximately the same as the Ibbotson estimate. Note also the larger variation in column 12, around this mean, relative to the variation in columns 11 and 13.

The results in Table II can be used to illustrate two primary advantages of the abnormal earnings model over the dividend growth model. First, the abnormal earnings approach uses more available "hard" data (current book value and forecast abnormal earnings for years +1 to +5) to reduce the emphasis on "softer" growth assumptions (g_{ae}) used to build terminal values. Figure 1 contains a value profile for the terms in equation (5), using data for 1991. This year was selected because it represents a "median" profile: the terminal value is a smaller (larger) fraction of total value for years before (after) 1991. Recall from Table II that our estimate for k in 1991 is 11.05 percent. The terminal value is based on abnormal earnings growing at an anticipated inflation rate of 5.04 percent (g_{ae} is three percent less than the risk-free rate of 8.04 percent). The value profile for the abnormal earn-

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ings model, represented by the solid columns in Figure 1, shows that approximately 50 percent of the total value is captured by current book value, 10 percent is spread over the abnormal earnings for the next five years, and about 40 percent remains in the terminal value. This last term is the only one affected by our growth assumption. In contrast, for the dividend growth model in equation (1), the dividend growth rate (g), which is assumed to equal the five-year analyst forecast for earnings growth (g_5 = 12.12 percent), is the primary determinant of the estimated k^* (= 15.16 percent).

To offer a different perspective on why growth assumptions are more influential for projected dividends, relative to abnormal earnings, we converted the abnormal earnings profile in Figure 1 to an isomorphic value profile for dividends, represented by the hollow columns in Figure 1. (Note that these dividends refer to the flows underlying k, from the abnormal earnings model, and are different from the flows underlying k^*, the dividend growth model estimate.) The year +5 terminal value for the dividend profile in Figure 1 corresponds to a dividend growth in perpetuity of 6.8 percent.[13] Even though the abnormal earnings and dividend profiles in Figure 1 correspond to the same underlying projections, the terminal value for the dividend profile represents almost 85 percent of total value. As a result, assumed dividend growth rates have a larger impact on estimated discount rates, relative to abnormal earnings growth rate assumptions. For example, doubling the assumed value of g_{ae} to 10 percent increases the estimated discount rate by only about two percentage points. In contrast, increasing the dividend growth assumption by one percentage point raises the estimated discount rate by almost the same amount.[14]

The second major benefit of the abnormal earnings approach is that we can narrow the range of reasonable growth assumptions (g_{ae}), relative to the assumed growth rate for dividends (g). Since g is a hypothetical rate, it is not easy to determine whether 12.12 percent (the value of g underlying our 1991 estimate for k^*) is more or less reasonable than the 6.8 percent dividend growth in perpetuity (after year +5) implied by our abnormal earnings model projections. Fortunately, restating implied dividend growth rates in terms of terminal growth in abnormal earnings makes it easier to see why some dividend growth assumptions are unreasonable. The assumption that dividends grow at 12.12 percent implies that abnormal earnings past year +5 would need to grow in perpetuity at about 15 percent per year in equa-

[13] This dividend growth rate is obtained by using equation (1) on projected market value in year +5, rather than current market values (p_0) and the dividend in year six is the dividend in year +5 (= 50 percent of the earnings forecast for year +5) times the unknown growth rate. That is, solve for g in the relation $p_5 = d_5(1 + g)/(k - g)$.

[14] Note that in equation (1), changes in g increase k^* by exactly the same amount. For the dividend value profile in Figure 1, however, dividends for years +1 to +5 have been fixed by forecasted earnings and dividend payout assumptions. Therefore, increases in the dividend growth rate underlying the terminal value increase the estimated discount rate by a slightly smaller amount.

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tion (5). This abnormal earnings growth rate corresponds to a real growth in rents of 10 percent (assumed long-term inflation rate is 5.04 percent), which is clearly an unreasonably optimistic assumption.

In sum, our estimates of the equity risk premium using the abnormal earnings approach are considerably lower than the Ibbotson rate, even though we believe the analyst forecasts we use, as well as the terminal growth assumptions we make, are optimistic. Adjusting for such optimism would lower our estimates further. While our estimates from the dividend growth approach are much closer to the Ibbotson rate, we believe they are biased upward because the assumed growth rate ($g = g_5$) is too high an estimate for dividend growth in perpetuity. The estimates from the abnormal earnings approach are more reliable because we use more available information to reduce the importance of assumed growth rates, and we are better able to reject growth rates as being infeasible by projecting rents rather than dividends. Additional benefits of using the abnormal earnings approach are illustrated in Section V.

IV. Equity Premium Estimates from Other Markets

Other equity markets offer a convenient opportunity to validate our domestic results. As long as the different markets are integrated with the United States and are of similar risk, those markets' estimates should proxy for the equity premium in the United States. We replicated the U.S. analysis on five other important equity markets with sufficient data to generate reasonably representative samples of those markets. Only a summary of our results is provided here; details of those analyses are in Claus and Thomas (1999b). The six markets exhibit considerable diversity in performance and underlying fundamentals over our sample period. This across-market variation increases the likelihood that the estimates we obtain from each market offer independent evidence.

As with the U.S. data, earnings forecasts, actual earnings per share, dividends per share, share prices, and the number of outstanding shares are obtained from I/B/E/S. Book values of equity as of the end of year 0 are collected from COMPUSTAT and Global Vantage for Canada and from Datastream for the remaining four countries. Unlike I/B/E/S and COMPUSTAT, Datastream drops firms that are no longer active. While such deletions are less frequent outside the United States, only surviving firms are included in our sample. Fortunately, no bias is created in this study since we equate market valuations with contemporaneous forecasts, and do not track performance.[15] Therefore, even if the surviving firms (included in our sample) performed systematically better or worse than firms that were dropped, our equity premium estimates are unbiased as long as market prices and earnings forecasts in each year are efficient and incorporate the same information.

[15] Note that there is no "backfilling" in our sample, where prior years' data for successful firms are entered subsequently.

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All data are denominated in local currency. Currency risk is not an issue here, since it is present in the required rates of returns for both equities and government bonds. Thus the difference between the two rates should be comparable across countries.

We find that analysts' forecasts in these five markets exhibit an optimism bias, similar to that observed in the United States. We considered other potential sources of measurement error in the forecasts, but are confident that any biases created by these errors are unlikely to alter our equity premium estimates much. For example, in Germany, earnings could be computed in as many as four different ways: GAAP per International Accounting Standards, German GAAP, DVFA, and U.S. GAAP.[16] I/B/E/S employees indicated that they have been more successful at achieving consistency in recent years (all forecasts are on a DVFA basis), but they are not as certain about earlier years in their database. While differences in basis between forecast and actual items would affect analyst bias, they do not affect our estimates of market discount rates. Differences in basis across analysts contaminate the consensus numbers used, but the estimated market discount rates are relatively insensitive to changes in the near-term forecasts used.

To select the month of analysis for each country, we followed the same logic as that for the U.S. analysis. December was the most popular fiscal year-end for all countries except for Japan, where it was March. We then identified the period after the fiscal year-end by which annual earnings are required to be disclosed. This period differs across countries (see Table 1 in Alford et al. (1993)): it is three months for Japan and the United States, four months for France, six months for Canada and the United Kingdom, and eight months for Germany. We selected the month following the reporting deadline as the "sure to be disclosed" month to collect forecasts for any given year.

To include a country-year in our sample, we required that the total market value of all firms in our sample exceed 35 percent of the market value of "primary stock holdings" for that country, as defined by Datastream. Although we used a low hurdle to ensure that our sample contained contiguous years for all countries, a substantially greater proportion of the Datastream Market Index than our minimum hurdle is represented for most country-years.

The equity-premium estimates using the abnormal earnings and dividend growth approaches as well as the prevailing risk-free rates for different country-year combinations with sufficient data are reported in Table III. The number of years with sufficient firms to represent the overall market was highest for Canada (all 14 years between 1985 and 1998), and lowest for Japan (8 years). As with the U.S. sample, we use a 50 percent aggregate

[16] The German financial analyst society, Deutsche Vereinigung für Finanzanalyse (DVFA), has developed a system used by analysts (and often by firms) to adjust reported earnings data to provide a measure that is closer to permanent or core earnings. The adjustment process uses both reported financial information as well as firms' internal records. GAAP refers to Generally Accepted Accounting Principles or the accounting rules under which financial statements are prepared in different domiciles.

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Table III

Implied Equity Premium Using Abnormal Earnings and Dividend Growth Approaches ($k - r_f$ and $k^* - r_f$) for International Stocks (1985 to 1998)

The market is an aggregate of firms on the I/B/E/S Summary files with forecasts for years +1, +2, and a five-year earnings growth estimate (g_5) as of April each year, and actual earnings, dividends, number of shares outstanding, and prices as of the end of the prior full fiscal year (year 0). Book values of equity for year 0 (bv_0) are obtained from COMPUSTAT, Global Vantage, and Datastream. Forecasted earnings for years +3, +4, and +5 are determined by applying g_5, the forecasted 5-year growth rate, to year +2 forecasted earnings. All amounts are measured in local currencies. r_f is the 10-year government bond yield. The implied discount rate that satisfies the valuation relation in equation (5) below is k. Abnormal earnings (ae_t) equal reported earnings less a charge for the cost of equity (= beginning book value of equity * k). Assuming that 50% of earnings are retained allows the estimation of future book values from current book values and forecast earnings. The terminal value represents all abnormal earnings beyond year +5. Those abnormal earnings are assumed to grow at a constant rate, g_{ae}, which is assumed to equal the expected inflation rate, and is set equal to r_f less 3 percent. The expected rate of return on the market is also estimated using equation (1), and is labeled k^*. Equation (1) is derived from the dividend growth model, and dividend growth in perpetuity, g, is assumed to equal the five-year earnings growth rate, g_5.

$$p_0 = bv_0 + \frac{ae_1}{(1+k)} + \frac{ae_2}{(1+k)^2} + \frac{ae_3}{(1+k)^3} + \frac{ae_4}{(1+k)^4} + \frac{ae_5}{(1+k)^5} + \left[\frac{ae_5(1+g_{ae})}{(k-g_{ae})(1+k)^5}\right] \tag{5}$$

$$k^* = \frac{d_1}{p_0} + g \tag{1}$$

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	Canada		France		Germany		Japan			
		k^*				k^*		k^*		k^*
	10.50%	4.41%	7.45%							
1986	3.82%	2.93%								
	3.16%	1.56%	4.53%		3.06%					
	3.66%	2.83%	4.67%		3.90%	6.78%	3.43%	4.59%		
	3.29%	3.08%		3.76%	3.64%	**5.11%**	**6.83%**	**3.87%**	5.48%	
		1.61%	2.97%	3.66%	3.04%	4.23%	8.99%	1.10%	3.23%	
			3.71%	3.81%	2.94%	4.41%	8.42%		4.72%	6.72%
	3.18%	0.42%	6.36%			**5.81%**	**7.89%**	**2.16%**	**5.03%**	**5.38%**
	7.32%					0.57%	6.14%	0.70%	4.19%	4.45%
			7.67%					1.30%	3.77%	4.24%
			6.77%			**10.04%**	**6.70%**	**2.22%**	3.84%	2.80%
			5.89%			**12.26%**	**6.41%**	**2.14%**	3.40%	3.17%
						9.69%	5.68%	2.28%	11.56%	2.47%
			7.44%	3.02%	2.53%					
			5.89%			7.90%	11%	2.02%	6.58%	3.86%
		1.55%	1.04%	1.62%		3.27%	1.04%	1.03%		1.67%

	Japan	
		k^*
	0.95%	0.38%
		0.34%
	1.05%	
	1.04%	4.56%
		9.50%
	2.79%	7.82%
	1.65%	
	1.99%	10.89%
	0.21%	5.83%
	1.31%	

		k^*
	10.16%	7.24%
	9.12%	2.77%
	7.64%	3.29%
		5.50%
	7.92%	3.34%
	7.02%	2.53%
	5.84%	2.09%
		7.91%

		k^*
		7.27%
		3.69%
		5.50%
		3.43%
		6.77%
		7.91%

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dividend payout ratio to generate future dividends and book values, and assume that abnormal earnings grow at the expected inflation rate, which is assumed to be three percent less than the prevailing risk-free rate. For the few years when r_f in Japan is below three percent, we set $g_{ae} = 0$.

The equity premium values based on the abnormal earnings approach $(k - r_f)$ generally lie between two and three percent, except for Japan, where the estimates are considerably lower (and even negative in the early 1990s). Finding that none of the almost 70 estimates of $k - r_f$ reported in Tables II and III are close to the Ibbotson estimate suggests strongly that that historical estimate is too high. In contrast, the equity premium estimates based on the dividend growth approach with dividends growing in perpetuity at the five-year earnings growth forecast (g_5) are considerably higher, similar to the pattern observed in the United States. The dividend growth estimates are very close to those reported in Khorana et al. (1997), which uses a similar approach and a similar sample.

Repeating the sensitivity analyses conducted on the United States (described in Section V) on these five markets produced similar conclusions. The abnormal earnings estimates generate projections that are consistent with experience, but the dividend growth estimates are biased upward and generate projections that are too optimistic because the five-year earnings growth forecast (g_5) is too high an estimate for dividend growth in perpetuity. The values of g_5 suggest mean real dividend growth rates in perpetuity that range between 6.09 percent for Canada and 8.25 percent for Japan. These real rates exceed historic real earnings growth rates, and are at least twice as high as the real GDP growth rates forecast for these countries.

The results observed for Japan are unusual and invite speculation. While our results suggest that the equity premium in Japan increased during the sample period, from about -1 percent in the early 1990s to 2 percent in the late 1990s, these results are also consistent with a stock market bubble that has gradually burst. That is, early in our sample period, prices were systematically higher than the fundamentals (represented by analysts' forecasts) would suggest, and have gradually declined to a level that is supported by analysts' forecasts. Note that our sample excludes the peak valuations in the late 1980s before the crash. Perhaps the implied equity premium in that period would be even more negative than the numbers we estimate for the early 1990s. Regardless of whether the poor performance of Japanese equities in the 1990s is due to correction of an earlier mispricing, it is useful to contrast the inferences from a historic approach with those from a forward-looking approach such as ours: the former would conclude that equity premia have fallen in Japan during the 1990s, whereas our approach suggests the opposite.

V. Sensitivity Analyses

This section summarizes our analysis of U.S. equity data designed to gauge the robustness of our conclusion that the equity premium is much lower

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than historic estimates. We begin by considering two relations for P/B and P/E ratios that allow us to check whether our projections under the dividend growth and abnormal earnings models are reasonable. Next, we document the extent of analyst optimism in our data. Finally, we consider the sensitivity of our risk premium estimates to the assumed abnormal earnings growth rate (g_{ae}).[17]

A. P/B Ratios and the Level of Future Profitability

The first relation we examine is that between the P/B ratio and future levels of profitability (e.g., Penman (1999)), where future profitability is the excess of the forecast market accounting rate of return (roe_t) over the required rate of return, k.

$$\frac{p_0}{bv_0} = 1 + \frac{roe_1 - k}{(1+k)} + \frac{roe_2 - k}{(1+k)^2}\left(\frac{bv_1}{bv_0}\right) + \frac{roe_3 - k}{(1+k)^3}\left(\frac{bv_2}{bv_0}\right) + \ldots, \tag{6}$$

where $roe_t = e_t/bv_{t-1}$ is the accounting return on equity in year t.

This relation indicates that the P/B ratio is explained by expected future profitability ($roe_t - k$).[18] Firms expected to earn an accounting rate of return on equity equal to the cost of capital should trade currently at book values ($p_0/bv_0 = 1$). Similarly, the P/B ratio expected in year +5 (p_5/bv_5), which is determined by the assumed growth in abnormal earnings after year +5 (g_{ae}), should be related to profitability beyond year +5. To investigate the validity of our assumed growth rates, we examine the profiles of future P/B ratios and profitability levels to check if they are reasonable and related to each other as predicted by equation (6). Future book values are generated by adding projected earnings and subtracting projected dividends (assuming a 50 percent payout) to the prior year's book value. Similarly, projected market values are obtained by growing the prior year's market value at the discount rate (k) less projected dividends.

Table IV provides data on current and projected values of P/B ratios and profitability. Current market and book values are reported in columns 1 and 2, and projected market and book values in year +5 are reported in columns

[17] We also examined Value Line data for the DOW 30 firms for two years: 1985 and 1995 (details in Claus and Thomas (1999a)). Value Line provides both dividend forecasts (over a four- or five-year horizon) and a projected price. This price is, in effect, a terminal value estimate, which obviates the need to assume dividend growth in perpetuity. Unfortunately, those risk premium estimates appear to be unreliable: The estimated discount rate is 20 percent (8.5 percent) for 1985 (1995). These results are consistent with Value Line believing that the DOW 30 firms are undervalued (overvalued) in 1985 (1995); that is, current price does not equal the present value of forecast dividends and projected prices. This view is supported by their recommendations for the proportion to be invested in equity: it was 100 percent through the 1980s, and declined through the 1990s (it is currently at 40 percent).

[18] The growth in book value terms in equation (6), bv_t/bv_0, which add a multiplicative effect, have been ignored in the discussion because of the built-in correlation with $roe_t - k$. Higher roe_t results in higher e_t, which in turn causes higher growth in bv_t because dividend payouts are held constant at 50 percent for all years.

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Table IV

Price-to-Book Ratios (p_t/bv_t), Forecast Accounting Return on Equity (roe_t) and Expected Rates of Return (k) for U.S. Stocks (1985 to 1998)

To examine the validity of assumptions underlying k, which is the implied discount rate that satisfies the valuation relation in equation (5), current price-to-book ratios are compared with estimated future returns on equity (roe_t) to examine fit with equation (6) below. The market is an aggregate of firms on the I/B/E/S Summary files with forecasts for years +1, +2, and a five-year earnings growth estimate (g_5) as of April each year, and actual earnings, dividends, number of shares outstanding, and prices as of the end of the prior full fiscal year (year 0). Book values of equity for year 0 (bv_0) are obtained from COMPUSTAT. When missing, forecasted earnings for years +3, +4, and +5 are determined by applying g_5 to year +2 forecasted earnings. Assuming that 50 percent of earnings are retained allows the estimation of future book values from current book values and forecast earnings. Return on equity (roe_t) equals forecast earnings scaled by beginning book value of equity (bv_{t-1}). Market and book value amounts are in millions of dollars.

$$p_0 = bv_0 + \frac{ae_1}{(1+k)} + \frac{ae_2}{(1+k)^2} + \frac{ae_3}{(1+k)^3} + \frac{ae_4}{(1+k)^4} + \frac{ae_5}{(1+k)^5} + \left[\frac{ae_5(1+g_{ae})}{(k-g_{ae})(1+k)^5}\right] \tag{5}$$

$$\frac{p_0}{bv_0} = 1 + \frac{roe_1 - k}{(1+k)} + \frac{roe_2 - k}{(1+k)^2}\left(\frac{bv_1}{bv_0}\right) + \tag{6}$$

Forecasts as of April	Year 0 Equity Values: Market Value (p_0)	Year 0 Equity Values: Book Value (bv_0)	Year +5 Equity Values: Market Value (p_5)	Year +5 Equity Values: Book Value (bv_5)	Price/Book Ratio: In Year 0 (p_0/bv_0)	Price/Book Ratio: In Year 5 (p_5/bv_5)	Forecast Accounting Return on Equity: In Year 1 (roe_1)	In Year 2 (roe_2)	In Year 3 (roe_3)	In Year 4 (roe_4)	In Year 5 (roe_5)	In Year 6 (roe_6)	k from Eq. (5)
	1	2	3	4	5	6	7	8	9	10	11	12	13
1985	1,747,133	1,191,869	2,676,683	1,768,036	1.5	1.5	15%	16%	16%	17%	17%	17%	14.38%
1986	2,284,245	1,214,454	3,197,490	1,783,987	1.9	1.8	15%	16%	16%	17%	17%	17%	11.28%
1987	2,640,743	1,323,899	3,727,459	1,936,215	2.0	1.9	14%	16%	16%	16%	17%	17%	11.12%
1988	2,615,857	1,430,672	3,779,033	2,122,648	1.8	1.8	16%	16%	16%	17%	17%	17%	12.15%
1989	2,858,585	1,541,231	4,200,867	2,341,029	1.9	1.8	17%	17%	17%	18%	18%	18%	12.75%
1990	3,143,879	1,636,069	4,589,685	2,465,373	1.9	1.9	16%	17%	17%	18%	18%	18%	12.33%
1991	3,660,296	1,775,199	5,181,184	2,597,264	2.1	2.0	14%	16%	16%	17%	17%	17%	11.05%
1992	4,001,756	1,911,383	5,574,848	2,773,918	2.1	2.0	13%	15%	16%	16%	17%	17%	10.57%
1993	4,918,359	2,140,668	6,595,210	3,139,088	2.3	2.1	14%	16%	16%	17%	17%	17%	9.62%
1994	5,282,046	2,168,446	7,336,322	3,301,664	2.4	2.2	16%	17%	18%	18%	19%	18%	10.47%
1995	6,289,760	2,670,725	8,837,148	4,132,682	2.4	2.1	17%	18%	18%	19%	19%	19%	11.03%
1996	8,207,274	3,182,952	11,206,787	4,853,189	2.6	2.3	16%	17%	18%	18%	19%	18%	9.96%
1997	10,198,036	3,679,110	14,103,523	5,708,609	2.8	2.5	17%	18%	18%	19%	20%	19%	10.12%
1998	12,908,495	3,412,303	16,838,377	5,378,478	3.8	3.1	17%	18%	19%	20%	21%	20%	8.15%
Mean					2.2	2.1	15%	17%	17%	18%	18%	18%	11.04%

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3 and 4. These values are used to generate current and year +5 P/B ratios, reported in columns 5 and 6. Columns 7 through 12 contain the forecasted accounting rate of return on equity for years 1 to 6, which can be compared with the estimated market discount rate, k, reported in column 13, to obtain forecasted profitability.

The current P/B ratio has been greater than 1 in every year in the sample period, and has increased steadily over time, from 1.5 in 1985 to 3.8 in 1998. Consistent with equation (6), all forecasted *roe* values for years 1 through 6 in Table IV exceed the corresponding values of k. Increases in the P/B ratio over the sample period are mirrored by corresponding increases in forecast profitability ($roe_t - k$) in years +1 through +5 as well as forecast profitability in the posthorizon period (after year +5), as measured by the implied price-to-book ratio in year +5. Finally, the tendency for P/B ratios to revert gradually over the horizon toward one (indicated by the year +5 values in column 6 being smaller than the year 0 values in column 5) is consistent with intuition (e.g., Nissim and Penman (1999)).

We also extended our investigation to years beyond year +5 for the assumptions underlying the abnormal earnings estimates, and find that the pattern of projections for P/B and *roe* remain reasonable. In contrast, those projections for the assumptions underlying the dividend growth model estimates suggest that the underlying growth rates are unreasonably high. To provide an illustrative example of those results, we contrast in Figure 2 the patterns for future *roe* and P/B that are projected for the dividend growth and abnormal earnings approaches for 1991. The *roe* levels are marked off on the left scale, and P/B ratios are shown on the right scale. Recall that the market discount rates estimated for the abnormal earnings and dividend growth approaches are 11.05 percent (k) and 15.16 percent (k^*) and the corresponding terminal growth rates for abnormal earnings and dividends are 5.04 percent and 12.12 percent.

The projections for the abnormal earnings method (indicated by bold lines) continue to remain reasonable. The P/B ratio always exceeds one, but it trends down over time. Consistent with P/B exceeding one, the *roe* is always above the 11.05 percent cost of capital, and trends toward it after year +5. Note that the optimistic analyst forecasts cause *roe* projections to climb for years +1 through +5, but the subsequent decline in *roe* is because the profitability growth implied by g_{ae} (our assumed growth in abnormal earnings past year +5) is lower than that implied by g_5.

The results for the dividend growth approach illustrate the benefits of using projected accounting ratios to validate assumed growth rates. The profitability (*roe*) is actually below the cost of equity of 15.16 percent (k^*), for the first three years, even though the P/B ratio is greater than one. Thereafter, the profitability keeps increasing, to a level above 20 percent by year +15. Both the high level of profitability and its increasing trend are not easily justified, especially when they are observed repeatedly for every year in our sample. Similarly, the increasing pattern for P/B, which is projected to increase from about two to about three by year +15, is hard to justify.

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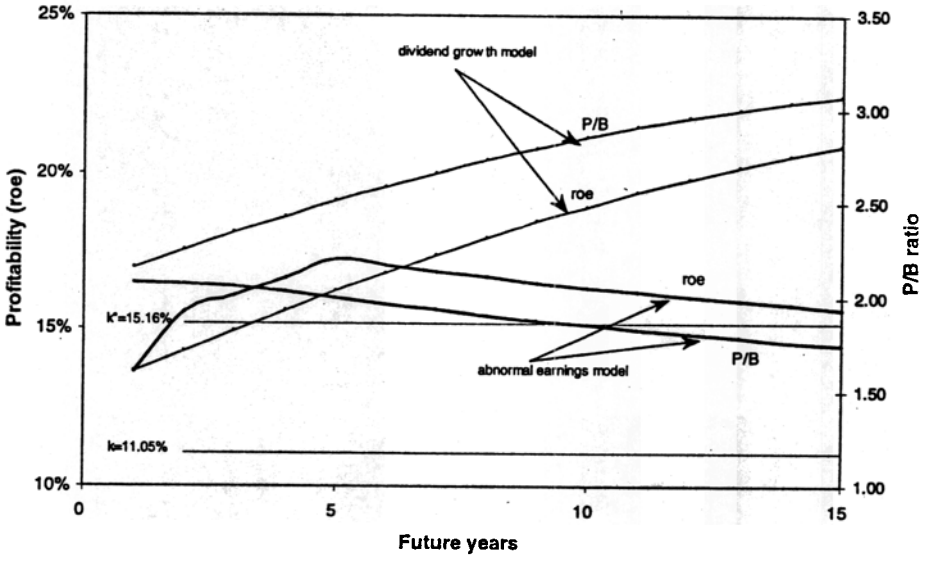

Figure 2. Pattern of future price-to-book (P/B) ratios and profitability, measured as excess of accounting return on equity (*roe*) over estimated discount rates (k^* and k), for dividend growth and abnormal earnings approaches for U.S. stocks as of April, 1991. For the dividend growth model described by equation (1) in Table II, dividends are assumed to grow at the consensus five-year earnings growth rate of 12.12 percent, and future *roe* is compared with the estimated market discount rate of 15.16 percent (k^*). For the abnormal earnings model described by equation (5) in Table II, abnormal earnings are assumed to grow at an anticipated inflation rate of 5.04 percent, and *roe* is compared with the estimated market discount rate of 11.05 percent (k). Projected P/B ratios are shown for both models.

These projections are, however, consistent with an estimated discount rate that is too high. Since near-term analysts' forecasts of profitability are below this discount rate, future levels of profitability have to be unreasonably high to compensate.

B. P/E Ratios and Forecast Growth in Profitability

The second relation we use to check the validity of our assumptions regarding g_{ae} is the price–earnings ratio, described by equation (7) (see derivation in Claus and Thomas, 1999a). Price–earnings ratios are a function of the present value of future changes in abnormal earnings, multiplied by a capitalization factor ($= 1/k$).

$$\frac{p_0}{e_1} = \frac{1}{k}\left[1 + \frac{\Delta ae_2}{e_1(1+k)} + \frac{\Delta ae_3}{e_1(1+k)} + \ldots\right], \tag{7}$$

where $\Delta ae_t = ae_t - ae_{t-1}$ is the change in expected abnormal earnings over the prior year.

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The price–earnings ratio on the left-hand side deviates slightly from the traditional representation in the sense that it is a "forward" price–earnings ratio, based on expected earnings for the upcoming year, rather than a "trailing" price–earnings ratio (p_0/e_0), which is based on earnings over the year just concluded. The relation between future earnings growth and forward price–earnings ratios is simpler than that for trailing price–earnings ratios.[19] Therefore, we use only the forward price–earnings ratio here and refer to it simply as the P/E ratio.

The results reported in Table V describe P/E ratios and growth in abnormal earnings derived from analysts' forecasts for the market. The first four columns provide market values and the corresponding upcoming expected earnings for year 0 and year +5. These numbers are used to generate the current and year +5 P/E ratios reported in columns 5 and 6, which can be compared to the values of $1/k$ reported in column 18.[20] According to equation (7), absent growth in abnormal earnings, the P/E ratio should be equal to $1/k$, and the P/E ratio should be greater (less) than $1/k$ for positive (negative) expected growth in abnormal earnings. Forecast growth rates in abnormal earnings for years +2 through +6 are reported in columns 7 through 11. To maintain equivalence with the terms in equation (7), growth in abnormal earnings is scaled by earnings expected for year +1 (e_1) and then discounted.

To understand the relations among the numbers in the different columns, consider the row corresponding to 1991. The market P/E ratio of 15.1 is higher than the inverse of the discount rate ($1/k = 9.0$). That difference of 6.1 is represented by the sum of the present value of the abnormal earnings growth terms in future years, scaled by e_1 (this sum needs to be multiplied by $1/k$ as shown in equation (7)). These growth terms decline from 13 percent in year 2 to 2 percent in year 6, and continue to decline thereafter. By year +5, the market P/E is expected to fall (to 11.7), since some of the growth in abnormal earnings (represented by the amounts in columns 7 through 11) is expected to have already occurred by then. Turning to the other sample years, the P/E ratios in year 0 (column 5) have generally increased through the sample period, and so have the values of $1/k$. Consistent with P/E ratios exceeding $1/k$ in every year, abnormal earnings are forecast to exhibit positive growth for all cells in columns 7 to 11. Also, the P/E ratios in year +5 are forecast to decline, relative to the corresponding year 0 P/E values, because of the value represented by the amounts in columns 7 to 11.

[19] Since the numerator of the P/E ratio is an ex-dividend price (p_0), the payment of a large dividend (d_0) would reduce p_0 without affecting trailing earnings (e_0), thereby destroying the relation between p_0 and e_0. This complication does not arise when expected earnings for the upcoming period (e_1) is used instead of e_0.

[20] If the numbers in Table V appear to be not as high as the trailing P/E ratios commonly reported in the popular press, note that forward P/E ratios are generally smaller than trailing P/E ratios for the following reasons. First, next year's earnings are greater than current earnings because of earnings growth. Second, current earnings contain one-time or transitory components that are on average negative, whereas forecast earnings focus on core or continuing earnings.

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For purposes of comparison with other work, we also report in columns 12 through 17 of Table V the growth in forecast earnings (as opposed to growth in abnormal earnings) for years +1 through +6. Forecasted growth in earnings declines over the horizon, similar to the pattern exhibited by growth in abnormal earnings. Note the similarity in the pattern of earnings growth for all years in the sample period: the magnitudes of earnings growth estimates appear to settle at around 12 percent by year +5, before dropping sharply to values around 7 percent in the posthorizon period (year +6). Again, this decline occurs because the earnings growth implied by g_{ae} (our assumed growth in abnormal earnings past year +5) is lower than g_5.

The results in Table V confirm the predictions derived from equation (7) as well as the intuitive links drawn in the literature. As with the results for P/B ratios, the trends for P/E ratios and growth in abnormal earnings exhibit no apparent discrepancies that might suggest that the assumptions underlying our abnormal earnings model are unreasonable.

C. Bias in Analyst Forecasts

We considered a variety of biases that may exist in the I/B/E/S forecasts, but found only the well-known optimism bias to be noteworthy (details provided in Claus and Thomas (1999a)).[21] We compute the forecast error for each firm in our sample, representing the median consensus forecast as of April less actual earnings, for different forecast horizons (year +1, +2, . . . +5) for each year between 1985 and 1997. Table VI contains the median forecast errors (across all firms in the sample for each year), scaled by share price. In general, forecasted earnings exceed actual earnings, and the extent of optimism increases with the horizon.[22] There is, however, a gradual reduction in optimism toward the end of the sample period.

Since the forecast errors in Table VI are scaled by price, comparing the magnitudes of the median forecast errors with the inverse of the trailing P/E ratios (or E/P ratios) is similar to a comparison of forecast errors with earnings levels. While the trailing E/P ratios for our sample vary between 5 and 9 percent, the forecast errors in Table VI vary between values that are in the neighborhood of 0.5 percent for year +1 to around 3 percent in year +5. Comparing the magnitudes of year +5 forecast errors with the implied E/P ratios indicates that forecasted earnings exceed actual earnings by as

[21] I/B/E/S removes one-time items (typically negative) from reported earnings. That is, the level of optimism would have been even higher if we had used reported numbers instead of actual earnings according to I/B/E/S.

[22] In addition to increasing with forecast horizon, the optimism bias is greater for certain years where earnings were depressed temporarily. The higher than average dividend payouts observed in Table I for 1987 and 1992 indicate temporarily depressed earnings in those years, and the forecast errors are also higher than average for those years. For example, the two largest median year +2 forecast errors are 1.86 and 1.81 percent, and they correspond to two-year out forecasts made in 1985 and 1990.

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Table V

Forward Price-to-Earnings Ratios (p_t/e_{t+1}) and Growth in Forecast Abnormal Earnings and Earnings for U.S. Stocks (1985 to 1998)

To examine the validity of assumptions underlying k, which is the implied discount rate that satisfies the valuation relation in equation (5), current and forecast forward price-to-earnings ratios are compared with growth in forecast abnormal earnings to examine fit with equation (7) below. The market is an aggregate of firms on the I/B/E/S Summary files with forecasts for years +1, +2, and a five-year earnings growth estimate (g_5) as of April each year, and actual earnings, dividends, number of shares outstanding, and prices as of the end of the prior full fiscal year (year 0). Book values of equity for year 0 (bv_0) are obtained from COMPUSTAT. Abnormal earnings (ae_t) equal reported earnings less a charge for the cost of equity (= beginning book value of equity * k). Future market values are projected for each year by multiplying beginning market values by $(1 + k)$ and subtracting dividends. When missing, forecasted earnings for years +3, +4, and +5 are determined by applying g_5 to year +2 forecasted earnings. Assuming that 50 percent of earnings are retained allows the estimation of future book values from current book values and forecast earnings. Market equity values and earnings amounts are in millions of dollars.

$$p_0 = bv_0 + \frac{ae_1}{(1+k)} + \frac{ae_2}{(1+k)^2} + \frac{ae_3}{(1+k)^3} + \frac{ae_4}{(1+k)^4} + \frac{ae_5}{(1+k)^5} + \left[\frac{ae_5(1+g_{ae})}{(k-g_{ae})(1+k)^5}\right] \tag{5}$$

$$\frac{p_0}{e_1} = \frac{1}{k}\left[1 + \frac{\Delta ae_2}{e_1(1+k)} + \frac{\Delta ae_3}{e_1(1+k)^2} + \ldots\right. \tag{7}$$

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Forecasts as of April	Year 0 Values: Market Value (p_0)	Year 0 Values: Earnings (e_1)	Year +5 Values: Market Value (p_5)	Year +5 Values: Earnings (e_6)	Forward P/E Ratio: In Year 0 (p_0/e_1)	Forward P/E Ratio: In Year 5 (p_5/e_6)	PV of ae Growth (Δae_t), Scaled by e_1: +2	+3	+4	+5	+6	Growth in Forecast Earnings: +1	+2	+3	+4	+5	+6	$1/k$ from Eq. (5)
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1985	1,747,133	180,945			9.7	8.7	5%	3%	3%	3%	1%	17%	13%	11%	11%	12%	9%	
1986	2,284,245	178,024			12.8	10.7	7%	4%	5%	5%	1%	15%	14%	11%	11%	11%	7%	
1987	2,640,743	186,319			14.2	11.5	10%	5%	5%	5%	1%	27%	18%	11%	11%	11%	7%	
1988	2,615,857	222,497			11.8	10.4	4%	4%	4%	4%	1%	33%	11%	11%	11%	11%	8%	
1989	2,858,585	261,278			10.9	10.0	2%	3%	3%	4%	1%	14%	9%	11%	11%	11%	8%	
1990	3,143,879	257,657			12.2	10.4	7%	4%	4%	4%	1%	13%	15%	11%	12%	12%	8%	
1991	3,660,296	241,760			15.1	11.7	13%	5%	6%	6%	2%	11%	22%	12%	12%	12%	7%	
1992	4,001,756	252,109			15.9	12.0	14%	6%	6%	6%	2%	25%	22%	12%	12%	12%	7%	
1993	4,918,359	295,862			16.6	12.4	13%	6%	7%	7%	1%	19%	20%	12%	12%	12%	6%	
1994	5,282,046	339,694			15.5	11.9	11%	6%	6%	7%	1%	17%	19%	12%	12%	12%	6%	
1995	6,289,760	444,593			14.1	11.3	9%	5%	6%	6%	2%	22%	17%	12%	12%	12%	7%	
1996	8,207,274	512,921			16.0	12.5	8%	6%	7%	7%	2%	15%	15%	12%	13%	13%	7%	
1997	10,198,036	614,932			16.6	12.8	8%	7%	7%	8%	2%	19%	16%	11%	12%	12%	7%	
1998	12,908,495	577,297			22.4	15.7	12%	9%	10%	11%	2%	19%	16%	11%	12%	12%	7%	
Mean					14.6	11.6	9%	5%	6%	6%	1%	19%	16%	11%	12%	12%	7%	

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Table VI

Optimism Bias in I/B/E/S Forecasts for U.S. Stocks: Median Forecast Errors for Forecasts Made Between 1985 and 1997

The following table represents the median of all forecast errors scaled by share price for each year examined. The forecast error is calculated for each firm as of April each year, and equals the median consensus forecasted earnings per share minus the actual earnings per share, scaled by price. The year when the forecasts were made is listed in the first row, while the first column lists the horizon of that forecast. For each year and horizon combination, we report the median forecast error and the number of firms in the sample. To interpret the Table, consider the values of 0.78 percent and 1,680 reported for the +1/1985 combination., in the top left-hand corner of the table. This means that the median value of the difference between the forecasted and actual earnings for 1986 was 0.78 percent of price, and that sample consisted of 1,680 firms with available forecast errors. The results confirm that analyst forecasts are systematically positively biased and that this bias increases with the forecast horizon; however, the extent of any such bias has been declining steadily over time.

		Year Forecast Was Made													
		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Mean
Forecast Year +1	Median	0.78%	0.65%	0.37%	0.07%	0.44%	0.58%	0.39%	0.17%	0.15%	0.03%	0.04%	0.00%	0.00%	0.28%
	Obs.	1,680	1,707	1,878	1,815	1,868	1,932	1,959	2,176	2,492	2,710	2,895	3,261	3,462	
Forecast Year +2	Median	2.05%	1.40%	0.79%	0.99%	1.74%	1.88%	1.21%	0.87%	0.58%	0.34%	0.32%	0.27%	—	1.04%
	Obs.	1,545	1,572	1,732	1,701	1,757	1,815	1,896	2,084	2,287	2,594	2,694	2,852	—	
Forecast Year +3	Median	2.84%	0.99%	1.44%	2.22%	2.78%	2.39%	1.50%	0.95%	0.63%	0.54%	0.45%	—	—	1.52%
	Obs.	1,406	1,449	1,596	1,576	1,634	1,744	1,826	1,936	2,159	2,396	2,346	—	—	
Forecast Year +4	Median	2.63%	2.04%	2.80%	3.19%	3.17%	2.83%	1.54%	0.91%	0.77%	0.60%	—	—	—	2.05%
	Obs.	1,285	1,344	1,492	1,474	1,586	1,696	1,724	1,825	2,024	2,132	—	—	—	
Forecast Year +5	Median	3.54%	3.44%	3.86%	3.59%	3.43%	2.91%	1.36%	0.94%	0.74%	—	—	—	—	2.65%
	Obs.	1,201	1,260	1,411	1,432	1,528	1,621	1,618	1,704	1,815	—	—	—	—	

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much as 50 percent at that horizon. These results suggest that our equity premium estimates are biased upward because we do not adjust for the considerable optimism in earnings forecasts for years +1 to +5. They also suggest that we are justified in dropping assumed growth rates for earnings past year +5 (column 17 versus column 16 in Table V).

D. Impact of Variation in the Assumed Growth Rate in Abnormal Earnings Beyond Year +5 (g_{ae})

We begin by considering two alternative cases for g_{ae}: three percent less and three percent more than our base case, where g_{ae} is assumed to equal the expected inflation rate. As mentioned in the Appendix, our base growth rate of $g_{ae} = r_f - 3\%$ is higher than any rate assumed in the prior abnormal earnings literature. Adding another three percent to the growth rate, which would require rents to grow at a three percent real rate in perpetuity, raises the level of optimism further. Dropping three percent from the base case, in the lower growth scenario, would be equivalent to assuming a very low nominal growth rate in abnormal earnings, and would be only slightly more optimistic than the assumptions in much of the prior abnormal earnings literature.

For the higher (lower) growth rate scenario, corresponding to $g_{ae} = r_f$ ($g_{ae} = r_f - 6\%$), the average risk premium over the 14-year sample period increases (decreases) to a mean of 4.66 (2.18), from a mean of 3.40 percent for the base case. Even for the high growth rate in abnormal earnings, the increase in the estimated risk premium is modest, and leaves it substantially below the traditional estimates of the risk premium. While increasing (decreasing) the growth rate increases (decreases) the terminal value, it also reduces (increases) the present value of that terminal value because of the higher (lower) discount rate it engenders.

We also considered a synthetic market portfolio each year constructed to have no expected future abnormal earnings, to avoid the need for an assumed abnormal earnings growth rate beyond year +5. As described in equation (6), portfolios with P/B = 1 should exhibit no abnormal earnings; that is, the roe_t should on average equal k for this synthetic market. The last term in equation (5), representing the terminal value of abnormal earnings beyond year +5, is set to zero and the estimates for k obtained iteratively each year. The mean estimate for $k - r_f$ from this synthetic market is 2.20 percent, which is slightly lower than the mean risk premium of 3.40 percent in Table II. Note that a lower discount rate is not expected for the synthetic market, since it has a beta close to one each year and has a lower P/B than the market. (Low P/B firms are expected to generate higher returns (e.g., Gebhardt, Lee, and Swaminathan (forthcoming).) The higher discount rates observed for the assumptions underlying our abnormal earnings model support our view that the analyst forecasts we use and our assumption that the terminal growth in abnormal earnings equals expected inflation ($g_{ae} = r_f - 3\%$) are both optimistic.

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VI. Conclusion

Barring some notable exceptions (e.g, Siegel (1992 and 1998), Blanchard (1993), Malkiel (1996), and Cornell (1999)), academic financial economists generally accept that the equity premium is around eight percent, based on the performance of the U.S. market since 1926. We claim that these estimates are too high for the post-1985 period that we examine, and the equity premium is probably no more than three percent. Our claim is based on estimates of the equity premium obtained for the six largest equity markets, derived by subtracting the 10-year risk-free rate from the discount rate that equates current prices to forecasted future flows (derived from I/B/E/S earnings forecasts). Growth rates in perpetuity for dividends and abnormal earnings need to be much higher than is plausible to justify equity premium estimates of about eight percent. Not only are such growth rates substantially in excess of any reasonable forecasts of aggregate growth (e.g., GDP), the projected streams for various indicators, such as price-to-book and price-to-earnings ratios, are also internally contradictory and inconsistent with intuition and past experience.

We agree that the weight of the evidence provided by the historical performance of U.S. stock markets since 1926 is considerable. Yet there are reasons to believe that this performance exceeded expectations, because of potential declines in the equity premium, good luck, and survivor bias. While projecting dividends to grow at earnings growth rates forecast by analysts provides equity premium estimates as high as eight percent, we show that those growth forecasts exhibit substantial optimism bias and need to be adjusted downward. In addition to our results, theory-based work, historical evidence from other periods and other markets, and surveys of institutional investors all suggest that the equity premium is much lower than eight percent. Overall, we believe that an eight percent equity premium is not supported by an analysis that compares current market prices with reasonable expectations of future flows for the markets and years that we examine.

Appendix: Assumed Growth Rates in Perpetuity for Dividends (g) and Abnormal Earnings (g_{ae})

While the conceptual definition of g is clear—it is the dividend growth rate that can be sustained in perpetuity, given current capital and future earnings[23]—determining this rate from fundamentals is not easy. To illustrate, take two firms that are similar in every way, except that they have announced different dividend policies in the current period, which results in a higher expected forward dividend yield (d_1/p_0) for one firm than the other, say 7 percent and 1 percent. What can be said about g for the two firms?

[23] Assuming too high a rate would cause the capital to be depleted in some future period, and assuming too low a rate would cause the capital to grow "too fast."

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Examination of equation (1) indicates that g for the low dividend yield firm must be 6 percent higher than g for the higher dividend yield firm, assuming they both have the same discount rate (k^*). If k^* equals 10 percent, for example, the value of g for the two firms must be 3 percent and 9 percent. These two values of g are substantially different from each other, even though the two firms are not.

In addition to being a hypothetical rate, g need not be related to historic or forecasted near-term growth rates for earnings or dividends. Dividend payout ratios can change over time because of changes in the investment opportunity set available and the relative attractiveness of cash dividends versus stock buybacks. Since changes in dividend payout affect the dividend yield, which in turn affects g, historic growth rates may not be relevant for g. Also, if dividend policies are likely to change over time, g need not be related to g_5 (the growth rate forecast for earnings over the next five years), a rate that is frequently used to proxy for g. Various scenarios can be constructed for the two firms in the example above to obtain similar historic and/or near-term forecast growth rates and yet have substantially different values for g.

Despite the difficulties noted above, both historic and forecast rates for aggregate dividends, earnings, and other macroeconomic measures (such as GDP) have been used as proxies for g. We note that these proxies create additional error. First, it is important to hold the unit of investment constant through the period where growth is measured. In particular, any growth created at the aggregate level by the issuance/retirement of equity since the beginning of the period should be ignored. Second, profits from all activities conducted outside the publicly traded corporate sector that are included in the macroeconomic measures should be deleted, and all overseas profits relating to this sector that are excluded from some macroeconomic measures should be included.

To control for the unit of investment problem, we use forecasted growth in per-share earnings rather than aggregate earnings, and to mitigate the problems associated with identifying g, we focus on growth in rents (abnormal earnings), g_{ae}, rather than dividends. To understand the benefits of switching to g_{ae}, it is important to describe some features of abnormal earnings. Expected abnormal earnings would equal zero if book values of equity reflected market values.[24] If book values measure input costs fairly, but do not include the portion of market values that represent economic rents (not yet earned), abnormal earnings would reflect those rents. However, the magnitude of such rents at the aggregate market level is likely to be small, and any rents that emerge are likely to be dissipated over time for the usual reasons (antitrust actions, global competition, etc.). As a result, much of the

[24] That is, if market prices are efficient and book values are marked to market values each period, market (book) values are expected to adjust each period so that no future abnormal returns (abnormal earnings) are expected.

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earlier literature using the abnormal earnings approach has assumed zero growth in abnormal earnings past the "horizon" date.[25]

Returning to the two-firm example, shifting the focus from growth in dividends to growth in rents removes much of the confusion caused by transitory changes in dividend payouts and dividend yields: these factors should have no impact on growth in rents, since the level of and growth in rents are determined by economic factors such as monopoly power. That is, even though the two firms have different forecasted earnings and dividends, the forecasted abnormal earnings and growth in abnormal earnings should be identical.

We believe, however, that the popular assumption of zero growth in abnormal earnings may be too pessimistic because accounting statements are conservative and understate input costs: assets (liabilities) tend to be understated (overstated) on average. For example, many investments (such as research and development, advertising, and purchased intangibles) are written off too rapidly in many domiciles. As a result, abnormal earnings tend to be positive, even in the absence of economic rents. Growth in abnormal earnings under conservative accounting is best understood by examining the behavior of the excess of *roe* (the accounting rate of return on the book value of equity) over k (the discount rate). Simulations and theoretical analyses (e.g., Zhang (2000)) of the steady-state behavior of the accounting rate of return under conservative accounting suggest two important determinants: the long-term growth in investment and the degree of accounting conservatism. These analyses also suggest that *roe* approaches k, but remains above it in the long-term.

Even though a decline in the excess of *roe* over k should cause the magnitude of abnormal earnings to fall over time, a countervailing factor is the growth in investment, which increases the base on which abnormal earnings are generated. We assume as a first approximation that the latter effect is greater than the former, and that abnormal earnings increase in perpetuity at the expected inflation rate. Since we recognize that this assumption is an approximation, we elected to err on the side of choosing too high a growth rate to ensure that our equity premium estimates are not biased downward. Also, we conduct sensitivity analyses to identify the impact on our equity premium estimates of varying the assumed growth rate within a reasonable range.

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[25] That is, abnormal earnings persist, but show no growth. Some papers are even more conservative, and have assumed that abnormal earnings drop to zero past the horizon date.

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The Equity Premium

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ABSTRACT

We estimate the equity premium using dividend and earnings growth rates to measure the expected rate of capital gain. Our estimates for 1951 to 2000, 2.55 percent and 4.32 percent, are much lower than the equity premium produced by the average stock return, 7.43 percent. Our evidence suggests that the high average return for 1951 to 2000 is due to a decline in discount rates that produces a large unexpected capital gain. Our main conclusion is that the average stock return of the last half-century is a lot higher than expected.

THE EQUITY PREMIUM—the difference between the expected return on the market portfolio of common stocks and the risk-free interest rate—is important in portfolio allocation decisions, estimates of the cost of capital, the debate about the advantages of investing Social Security funds in stocks, and many other applications. The average return on a broad portfolio of stocks is typically used to estimate the expected market return. The average real return for 1872 to 2000 on the S&P index (a common proxy for the market portfolio, also used here) is 8.81 percent per year. The average real return on six-month commercial paper (a proxy for the risk-free interest rate) is 3.24 percent. This large spread (5.57 percent) between the average stock return and the interest rate is the source of the so-called equity premium puzzle: Stock returns seem too high given the observed volatility of consumption (Mehra and Prescott (1985)).

We use fundamentals (dividends and earnings) to estimate the expected stock return. Along with other evidence, the expected return estimates from fundamentals help us judge whether the realized average return is high or low relative to the expected value.

The logic of our approach is straightforward. The average stock return is the average dividend yield plus the average rate of capital gain:

$$A(R_t) = A(D_t/P_{t-1}) + A(GP_t), \tag{1}$$

* Fama is from the University of Chicago and French is from Dartmouth College. The comments of John Campbell, John Cochrane, Kent Daniel, John Heaton, Jay Ritter, Andrei Shleifer, Rex Sinquefield, Tuomo Vuolteenaho, Paul Zarowin, and seminar participants at Boston College, Dartmouth College, the NBER, Purdue University, the University of Chicago, and Washington University have been helpful. Richard Green (the editor) and the two referees get special thanks.

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where D_t is the dividend for year t, P_{t-1} is the price at the end of year $t-1$, $GP_t = (P_t - P_{t-1})/P_{t-1}$ is the rate of capital gain, and $A(\ )$ indicates an average value. (Throughout the paper, we refer to D_t/P_t as the dividend yield and D_t/P_t is the dividend–price ratio. Similarly, Y_t/P_{t-1}, the ratio of earnings for year t to price at the end of year $t-1$, is the earnings yield and Y_t/P_t is the earnings–price ratio.)

Suppose the dividend–price ratio, D_t/P_t, is stationary (mean reverting). Stationarity implies that if the sample period is long, the compound rate of dividend growth approaches the compound rate of capital gain. Thus, an alternative estimate of the expected stock return is

$$A(RD_t) = A(D_t/P_{t-1}) + A(GD_t), \tag{2}$$

where $GD_t = (D_t - D_{t-1})/D_{t-1}$ is the growth rate of dividends. We call (2) the dividend growth model.

The logic that leads to (2) applies to any variable that is cointegrated with the stock price. For example, the dividend–price ratio may be nonstationary because firms move away from dividends toward share repurchases as a way of returning earnings to stockholders. But if the earnings–price ratio, Y_t/P_t, is stationary, the average growth rate of earnings, $A(GY_t) = A((Y_t - Y_{t-1})/Y_{t-1})$, is an alternative estimate of the expected rate of capital gain. And $A(GY_t)$ can be combined with the average dividend yield to produce another estimate of the expected stock return:

$$A(RY_t) = A(D_t/P_{t-1}) + A(GY_t). \tag{3}$$

We call (3) the earnings growth model.[1]

We should be clear about the expected return concept targeted by (1), (2), and (3). D_t/P_t and Y_t/P_t vary through time because of variation in the conditional (point-in-time) expected stock return and the conditional expected growth rates of dividends and earnings (see, e.g., Campbell and Shiller (1989)). But if the stock return and the growth rates are stationary (they have constant unconditional means), D_t/P_t and Y_t/P_t are stationary. Then, like the average return (1), the dividend and earnings growth models (2) and (3) provide estimates of the unconditional expected stock return. In short, the focus of the paper is estimates of the unconditional expected stock return.

The estimate of the expected real equity premium for 1872 to 2000 from the dividend growth model (2) is 3.54 percent per year. The estimate from the average stock return, 5.57 percent, is almost 60 percent higher. The difference between the two is largely due to the last 50 years. The equity premium for 1872 to 1950 from the dividend growth model, 4.17 percent per year, is close to the estimate from the average return, 4.40 percent. In con-

[1] Motivated by the model in Lettau and Ludvigson (2001), one can argue that if the ratio of consumption to stock market wealth is stationary, the average growth rate of consumption is another estimate of the expected rate of capital gain. We leave this path to future work.

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trast, the equity premium for 1951 to 2000 produced by the average return, 7.43 percent per year, is almost three times the estimate, 2.55 percent, from (2). The estimate of the expected real equity premium for 1951 to 2000 from the earnings growth model (3), 4.32 percent per year, is larger than the estimate from the dividend growth model (2). But the earnings growth estimate is still less than 60 percent of the estimate from the average return.

Three types of evidence suggest that the lower equity premium estimates for 1951 to 2000 from fundamentals are closer to the expected premium. (a) The estimates from fundamentals are more precise. For example, the standard error of the estimate from the dividend growth model is less than half the standard error of the estimate from the average return. (b) The Sharpe ratio for the equity premium from the average stock return for 1951 to 2000 is just about double that for 1872 to 1950. In contrast, the equity premium from the dividend growth model has a similar Sharpe ratio for 1872 to 1950 and 1951 to 2000. (c) Most important, valuation theory specifies relations among the book-to-market ratio, the return on investment, and the cost of equity capital (the expected stock return). The estimates of the expected stock return for 1951 to 2000 from the dividend and earnings growth models line up with other fundamentals in the way valuation theory predicts. But the book-to-market ratio and the return on investment suggest that the expected return estimate from the average stock return is too high.

Our motivation for the dividend growth model (2) is simpler and more general, but (2) can be viewed as the expected stock return estimate of the Gordon (1962) model. Our work is thus in the spirit of a growing literature that uses valuation models to estimate expected returns (e.g., Blanchard (1993), Claus and Thomas (2001), and Gebhardt, Lee, and Swaminathan (2001)). Claus and Thomas and Gebhardt, Lee, and Swaminathan use forecasts by security analysts to estimate expected cash flows. Their analyst forecasts cover short periods (1985 to 1998 and 1979 to 1995). We use realized dividends and earnings from 1872 to 2000. This 129-year period provides a long perspective, which is important for judging the competing expected return estimates from fundamentals and realized stock returns. Moreover, though the issue is controversial (Keane and Runkle (1998)), Claus and Thomas find that analyst forecasts are biased; they tend to be substantially above observed growth rates. The average growth rates of dividends and earnings we use are unbiased estimates of expected growth rates.

Like us, Blanchard (1993) uses dividend growth rates to estimate the expected rate of capital gain, which he combines with an expected dividend yield to estimate the expected stock return. But his focus is different and his approach is more complicated than ours. He is interested in the path of the conditional expected stock return. His conditional expected return is the sum of the fitted values from time-series regressions of the realized dividend yield and a weighted average of 20 years of future dividend growth rates on four predetermined variables (the dividend yield, the real rate of capital gain, and the levels of interest rates and inflation). He focuses on describing the path of the conditional expected return in terms of his four explanatory variables.

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In contrast, our prime interest is the unconditional expected return, which we estimate more simply as the sum of the average dividend yield and the average growth rate of dividends or earnings. This approach is valid if the dividend–price and earnings–price ratios are stationary. And we argue below that it continues to produce estimates of the average expected stock return when the price ratios are subject to reasonable forms of nonstationarity. Given its simplicity and generality, our approach is an attractive addition to the research toolbox for estimating the expected stock return.

Moreover, our focus is comparing alternative estimates of the unconditional expected stock return over the long 1872 to 2000 period, and explaining why the expected return estimates for 1951 to 2000 from fundamentals are much lower than the average return. Our evidence suggests that much of the high return for 1951 to 2000 is unexpected capital gain, the result of a decline in discount rates.

Specifically, the dividend–price and earnings–price ratios fall from 1950 to 2000; the cumulative percent capital gain for the period is more than three times the percent growth in dividends or earnings. All valuation models agree that the two price ratios are driven by expectations about future returns (discount rates) and expectations about dividend and earnings growth. Confirming Campbell (1991), Cochrane (1994), and Campbell and Shiller (1998), we find that dividend and earnings growth rates for 1950 to 2000 are largely unpredictable. Like Campbell and Shiller (1998), we thus infer that the decline in the price ratios is mostly due to a decline in expected returns. Some of this decline is probably expected, the result of reversion of a high 1950 conditional expected return to the unconditional mean. But most of the decline in the price ratios seems to be due to the unexpected decline of expected returns to ending values far below the mean.

The paper proceeds as follows. The main task, addressed in Sections I and II, is to compare and evaluate the estimates of the unconditional annual expected stock return provided by the average stock return and the dividend and earnings growth models. Section III then considers the issues that arise if the goal is to estimate the long-term expected growth of wealth, rather than the unconditional expected annual (simple) return. Section IV concludes.

I. The Unconditional Annual Expected Stock Return

Table I shows estimates of the annual expected real equity premium for 1872 to 2000. The market portfolio is the S&P 500 and its antecedents. The deflator is the Producer Price Index until 1925 (from Shiller (1989)) and the Consumer Price Index thereafter (from Ibbotson Associates). The risk-free interest rate is the annual real return on six-month commercial paper, rolled over at midyear. The risk-free rate and S&P earnings data are from Shiller, updated by Vuolteenaho (2000) and us. Beginning in 1925, we construct S&P book equity data from the book equity data in Davis, Fama, and French (2000), expanded to include all NYSE firms. The data on dividends, prices, and returns for 1872 to 1925 are from Shiller. Shiller's annual data on the

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Table I

Real Equity Premium and Related Statistics for the S&P Portfolio

The inflation rate for year t is $Inf_t = L_t/L_{t-1} - 1$, where L_t is the price level at the end of year t. The real return for year t on six-month (three-month for the year 2000) commercial paper (rolled over at midyear) is F_t. The nominal values of book equity and price for the S&P index at the end of year t are b_t and p_t. Nominal S&P dividends and earnings for year t are d_t and y_t. Real rates of growth of dividends, earnings, and the stock price are $GD_t = (d_t/d_{t-1})*(L_{t-1}/L_t) - 1$, $GY_t = (y_t/y_{t-1})*(L_{t-1}/L_t) - 1$, and $GP_t = (p_t/p_{t-1})*(L_{t-1}/L_t) - 1$. The real dividend yield is $D_t/P_{t-1} = (d_t/p_{t-1})*(L_{t-1}/L_t)$. The real income return on investment is $Y_t/B_{t-1} = (1 + y_t/b_{t-1})*(L_{t-1}/L_t) - 1$. The dividend growth estimate of the real S&P return for t is $RD_t = D_t/P_{t-1} + GD_t$, the earnings growth estimate is $RY_t = D_t/P_{t-1} + GY_t$, and R_t is the realized real S&P return. The dividend and earnings growth estimates of the real equity premium for year t are $RXD_t = RD_t - F_t$ and $RXY_t = RY_t - F_t$, and $RX_t = R_t - F_t$ is the real equity premium from the realized real return. The Sharpe ratio for $RD_t - F_t$ (the mean of $RD_t - F_t$ divided by the standard deviation of R_t) is SD, SY is the Sharpe ratio for $RY_t - F_t$ (the mean of $RY_t - F_t$ divided by the standard deviation of R_t), and SR is the Sharpe ratio for $R_t - F_t$ (the mean of $R_t - F_t$ divided by the standard deviation of R_t). Except for the Sharpe ratios, all variables are expressed as percents, that is, they are multiplied by 100.

	Inf_t	F_t	D_t/P_{t-1}	GD_t	GY_t	GP_t	RD_t	RY_t	R_t	RXD_t	RXY_t	RX_t	SD	SY	SR
Means of annual values of variables															
1872–2000	2.16	3.24	4.70	2.08	NA	4.11	6.78	NA	8.81	3.54	NA	5.57	0.20	NA	0.31
1872–1950	0.99	3.90	5.34	2.74	NA	2.96	8.07	NA	8.30	4.17	NA	4.40	0.22	NA	0.23
1951–2000	4.00	2.19	3.70	1.05	2.82	5.92	4.74	6.51	9.62	2.55	4.32	7.43	0.15	0.25	0.44
Standard deviations of annual values of variables															
1872–2000	7.51	8.48	1.39	12.37	NA	17.83	12.56	NA	18.03	13.00	NA	18.51			
1872–1950	9.11	10.63	1.12	15.28	NA	18.48	15.41	NA	18.72	16.02	NA	19.57			
1951–2000	3.11	2.46	1.17	5.09	13.79	16.77	5.21	13.51	17.03	5.62	14.02	16.73			
Means of annual continuously compounded returns and growth rates															
1872–2000	1.86	2.87		1.34	NA	2.48			7.00						
1872–1950	0.59	3.33		1.60	NA	1.22			6.41						
1951–2000	3.88	2.14		0.92	1.89	4.46			7.94						

	b_t/p_t	RD_t	RY_t	R_t	Y_t/B_{t-1}
Means of annual values of variables					
1951–2000	0.66	4.74	6.51	9.62	7.60

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level of the S&P (used to compute returns and other variables involving price) are averages of daily January values. The S&P dividend, price, and return data for 1926 to 2000 are from Ibbotson Associates, and the returns for 1926 to 2000 are true annual returns.

Without showing the details, we can report that the CRSP value-weight portfolio of NYSE, AMEX, and Nasdaq stocks produces average returns and dividend growth estimates of the expected return close to the S&P estimates for periods after 1925 when both indices are available. What one takes to be the risk-free rate has a bigger effect. For example, substituting the one-month Treasury bill rate for the six-month commercial paper rate causes estimates of the annual equity premium for 1951 to 2000 to rise by about one percent. But for our main task—comparing equity premium estimates from (1), (2), and (3)—differences in the risk-free rate are an additive constant that does not affect inferences.

One can estimate expected returns in real or nominal terms. Since portfolio theory says the goal of investment is consumption, real returns seem more relevant, and only results for real returns are shown. Because of suspicions about the quality of the price deflator during the early years of 1872 to 2000, we have replicated the results for nominal returns. They support all the inferences from real returns.

The dividend and earnings growth models (2) and (3) assume that the market dividend–price and earnings–price ratios are stationary. The first three annual autocorrelations of D_t/P_t for 1872 to 2000 are 0.73, 0.51, and 0.47. For the 1951 to 2000 period that occupies much of our attention, the autocorrelations are 0.83, 0.72, and 0.69. The autocorrelations are large, but their decay is roughly like that of a stationary first-order autoregression (AR1). This is in line with formal evidence (Fama and French (1988), Cochrane (1994), and Lamont (1998)) that the market dividend–price ratio is highly autocorrelated but slowly mean-reverting. S&P earnings data for the early years of 1872 to 2000 are of dubious quality (Shiller (1989)), so we estimate expected returns with the earnings growth model (3) only for 1951 to 2000. The first three autocorrelations of Y_t/P_t for 1951 to 2000, 0.80, 0.70, and 0.61, are again roughly like those of a stationary AR1.

We emphasize, however, that our tests are robust to reasonable nonstationarity of D_t/P_t and Y_t/P_t. It is not reasonable that the expected stock return and the expected growth rates of dividends and earnings that drive D_t/P_t and Y_t/P_t are nonstationary processes that can wander off to infinity. But nonstationarity of D_t/P_t and Y_t/P_t due to structural shifts in productivity or preferences that permanently change the expected return or the expected growth rates is reasonable. Such regime shifts are not a problem for the expected return estimates from (2) and (3), as long as D_t/P_t and Y_t/P_t mean-revert within regimes. If the regime shift is limited to expected dividend and earnings growth rates, the permanent change in expected growth rates is offset by a permanent change in the expected dividend yield, and (2) and (3) continue to estimate the (stationary) expected stock return. (An Appendix, available on request, provides an example.) If there is a perma-

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nent shift in the expected stock return, it is nonstationary, but like the average return in (1), the dividend and earnings growth models in (2) and (3) estimate the average expected return during the sample period.

Indeed, an advantage of the expected return estimates from fundamentals is that they are likely to be less sensitive than the average return to long-lived shocks to dividend and earnings growth rates or the expected stock return. For example, a permanent shift in the expected return affects the average dividend yield, which is common to the three expected return estimates, but it produces a shock to the capital gain term in the average return in (1) that is not shared by the estimates in (2) and (3). In short, the estimates of the expected stock return from fundamentals are likely to be more precise than the average stock return.

A. *The Equity Premium*

For much of the period from 1872 to 2000—up to about 1950—the dividend growth model and the average stock return produce similar estimates of the expected return. Thereafter, the two estimates diverge. To illustrate, Table I shows results for 1872 to 1950 (79 years) and 1951 to 2000 (50 years). The year 1950 is a big year, with a high real stock return (23.40 percent), and high dividend and earnings growth estimates of the return (29.96 percent and 24.00 percent). But because the three estimates of the 1950 return are similarly high, the ordering of expected return estimates, and the inferences we draw from them, are unaffected by whether 1950 is allocated to the earlier or the later period. Indeed, pushing the 1950 break-year backward or forward several years does not affect our inferences.

For the earlier 1872 to 1950 period, there is not much reason to favor the dividend growth estimate of the expected stock return over the average return. Precision is not an issue; the standard errors of the two estimates are similar (1.74 percent and 2.12 percent), the result of similar standard deviations of the annual dividend growth rate and the rate of capital gain, 15.28 percent and 18.48 percent. Moreover, the dividend growth model and the average return provide similar estimates of the expected annual real return for 1872 to 1950, 8.07 percent and 8.30 percent. Given similar estimates of the expected return, the two approaches produce similar real equity premiums for 1872 to 1950, 4.17 percent (dividend growth model) and 4.40 percent (stock returns).

The competition between the dividend growth model and the average stock return is more interesting for 1951 to 2000. The dividend growth estimate of the 1951 to 2000 expected return, 4.74 percent, is less than half the average return, 9.62 percent. The dividend growth estimate of the equity premium, 2.55 percent, is 34 percent of the estimate from returns, 7.43 percent. The 1951 to 2000 estimates of the expected stock return and the equity premium from the earnings growth model, 6.51 percent and 4.32 percent, are higher than for the dividend growth model. But they are well below the estimates from the average return, 9.62 percent and 7.43 percent.

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B. Evaluating the Expected Return Estimates for 1951 to 2000

We judge that the estimates of the expected stock return for 1951 to 2000 from fundamentals are closer to the true expected value, for three reasons.

(a) The expected return estimates from the dividend and earnings growth models are more precise than the average return. The standard error of the dividend growth estimate of the expected return for 1951 to 2000 is 0.74 percent, versus 2.43 percent for the average stock return. Since earnings growth is more volatile than dividend growth, the standard error of the expected return from the earnings growth model, 1.93 percent, is higher than the estimate from the dividend growth model, but it is smaller than the 2.43 percent standard error of the average stock return. Claus and Thomas (2001) also argue that expected return estimates from fundamentals are more precise than average returns, but they provide no direct evidence.

(b) Table I shows Sharpe ratios for the three equity premium estimates. Only the average premium in the numerator of the Sharpe ratio differs for the three estimates. The denominator for all three is the standard deviation of the annual stock return. The Sharpe ratio for the dividend growth estimate of the equity premium for 1872 to 1950, 0.22, is close to that produced by the average stock return, 0.23. More interesting, the Sharpe ratio for the equity premium for 1951 to 2000 from the dividend growth model, 0.15, is lower than but similar to that for 1872 to 1950. The Sharpe ratio for the 1951 to 2000 equity premium from the earnings growth model, 0.25, is somewhat higher than the dividend growth estimate, 0.15, but it is similar to the estimates for 1872 to 1950 from the dividend growth model, 0.22, and the average return, 0.23.

In asset pricing theory, the Sharpe ratio is related to aggregate risk aversion. The Sharpe ratios for the 1872 to 1950 and 1951 to 2000 equity premiums from the dividend growth model and the earnings growth model suggest that aggregate risk aversion is roughly similar in the two periods. In contrast, though return volatility falls a bit, the equity premium estimate from the average stock return increases from 4.40 percent for 1872 to 1950 to 7.43 percent for 1951 to 2000, and its Sharpe ratio about doubles, from 0.23 to 0.44. It seems implausible that risk aversion increases so much from the earlier to the later period.

(c) Most important, the behavior of other fundamentals favors the dividend and earnings growth models. The average ratio of the book value of equity to the market value of equity for 1951 to 2000 is 0.66, the book-to-market ratio B_t/P_t is never greater than 1.12, and it is greater than 1.0 for only 6 years of the 50-year period. Since, on average, the market value of equity is substantially higher than its book value, it seems safe to conclude that, on average, the expected return on investment exceeds the cost of capital.

Suppose investment at time $t - 1$ generates a stream of equity earnings for $t, t + 1, \ldots, t + N$ with a constant expected value. The average income return on book equity, $A(Y_t/B_{t-1})$, is then an estimate of the expected return on equity's share of assets. It is an unbiased estimate when N is infinite and

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it is upward biased when N is finite. In either case, if the expected return on investment exceeds the cost of capital, we should find that (except for sampling error) the average income return on book equity is greater than estimates of the cost of equity capital (the expected stock return):

$$A(Y_t/B_{t-1}) > E(R). \tag{4}$$

Table I shows that (4) is confirmed when we use the dividend and earnings growth models to estimate the expected real stock return for 1951 to 2000. The estimates of $E(R)$, 4.74 percent (dividend growth model) and 6.51 percent (earnings growth model), are below 7.60 percent, the average real income return on book equity, $A(Y_t/B_{t-1})$. In contrast, the average real stock return for 1951 to 2000, 9.62 percent, exceeds the average income return by more than 2 percent. An expected stock return that exceeds the expected income return on book equity implies that the typical corporate investment has a negative net present value. This is difficult to reconcile with an average book-to-market ratio substantially less than one.

To what extent are our results new? Using analyst forecasts of expected cash flows and a more complicated valuation model, Claus and Thomas (2001) produce estimates of the expected stock return for 1985 to 1998 far below the average return. Like us, they argue that the estimates from fundamentals are closer to the true expected return. We buttress this conclusion with new results on three fronts. (a) The long-term perspective provided by the evidence that, for much of the 1872 to 2000 period, average returns and fundamentals produce similar estimates of the expected return. (b) Direct evidence that the expected return estimates for 1951 to 2000 from fundamentals are more precise. (c) Sharpe ratios and evidence on how the alternative expected return estimates line up with the income return on investment. These new results provide support for the expected return estimates from fundamentals, and for the more specific inference that the average stock return for 1951 to 2000 is above the expected return.

II. Unexpected Capital Gains

Valuation theory suggests three potential explanations for why the 1951 to 2000 average stock return is larger than the expected return. (a) Dividend and earnings growth for 1951 to 2000 is unexpectedly high. (b) The expected (post-2000) growth rates of dividends and earnings are unexpectedly high. (c) The expected stock return (the equity discount rate) is unexpectedly low at the end of the sample period.

A. Is Dividend Growth for 1951 to 2000 Unexpectedly High?

If the prosperity of the United States over the last 50 years was not fully anticipated, dividend and earnings growth for 1951 to 2000 exceed 1950 expectations. Such unexpected in-sample growth produces unexpected cap-

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ital gains. But it does not explain why the average return for 1951 to 2000 (the average dividend yield plus the average rate of capital gain) is so much higher than the expected return estimates from fundamentals (the average dividend yield plus the average growth rate of dividends or earnings). To see the point, note that unexpected in-sample dividend and earnings growth do not affect either the 1950 or the 2000 dividend–price and earnings–price ratios. (The 2000 ratios depend on post-2000 expected returns and growth rates.) Suppose D_t/P_t and E_t/P_t were the same in 1950 and 2000. Then the total percent growth in dividends and earnings during the period would be the same as the percent growth in the stock price. And (1), (2), and (3) would provide similar estimates of the expected stock return.

It is worth dwelling on this point. There is probably survivor bias in the U.S. average stock return for 1872 to 1950, as well as for 1951 to 2000. During the 1872 to 2000 period, it was not a foregone conclusion that the U.S. equity market would survive several financial panics, the Great Depression, two world wars, and the cold war. The average return for a market that survives many potentially cataclysmic challenges is likely to be higher than the expected return (Brown, Goetzmann, and Ross (1995)). But if the positive bias shows up only as higher than expected dividend and earnings growth during the sample period, there is similar survivor bias in the expected return estimates from fundamentals—a problem we do not solve. Our more limited goal is to explain why the average stock return for 1951 to 2000 is so high relative to the expected return estimates from the dividend and earnings growth models.

Since unexpected growth for 1951 to 2000 has a similar effect on the three expected return estimates, the task of explaining why the estimates are so different falls to the end-of-sample values of future expected returns and expected dividend and earnings growth. We approach the problem by first looking for evidence that expected dividend or earnings growth is high at the end of the sample period. We find none. We then argue that the large spread of capital gains over dividend and earnings growth for 1951 to 2000, or equivalently, the low end-of-sample dividend–price and earnings–price ratios, are due to an unexpected decline in expected stock returns to unusually low end-of-sample values.

B. Are Post-2000 Expected Dividend and Earnings Growth Rates Unusually High?

The behavior of dividends and earnings provides little evidence that rationally assessed (i.e., true) long-term expected growth is high at the end of the sample period. If anything, the growth rate of real dividends declines during the 1951 to 2000 period (Table II). The average growth rate for the first two decades, 1.60 percent, is higher than the average growth rates for the last three, 0.68 percent. The regressions in Table III are more formal evidence on the best forecast of post-2000 real dividend growth rates. Re-

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Table II

Means of Simple Real Equity Premium and Related Statistics for the S&P Portfolio for 10-year Periods

The inflation rate for year t is $Inf_t = L_t/L_{t-1} - 1$, where L_t is the price level at the end of year t. The real return for year t on six-month (three-month for the year 2000) commercial paper (rolled over at midyear) is F_t. The nominal price of the S&P index at the end of year t is p_t. Nominal S&P dividends and earnings for year t are d_t and y_t. Real rates of growth of dividends, earnings, and the stock price are $GD_t = (d_t/d_{t-1})*(L_{t-1}/L_t) - 1$, $GY_t = (y_t/y_{t-1})*(L_{t-1}/L_t) - 1$, and $GP_t = (p_t/p_{t-1})*(L_{t-1}/L_t) - 1$. The real dividend yield is $D_t/P_{t-1} = (d_t/p_{t-1})*(L_{t-1}/L_t)$. The dividend growth estimate of the real S&P return for t is $RD_t = D_t/P_{t-1} + GD_t$, the earnings growth estimate is $RY_t = D_t/P_{t-1} + GY_t$, and R_t is the realized real S&P return. The dividend and earnings growth estimates of the real equity premium for year t are $RXD_t = RD_t - F_t$ and $RXY_t = RY_t - F_t$, and $RX_t = R_t - F_t$ is the real equity premium from the realized real return. All variables are expressed as percents, that is, they are multiplied by 100.

	Inf_t	F_t	D_t/P_{t-1}	GD_t	GY_t	GP_t	RD_t	RY_t	R_t	RXD_t	RXY_t	RX_t
1872–1880	−2.77	9.86	6.29	4.62		7.13	10.91		13.42	1.06		3.56
1881–1890	−1.72	7.23	5.04	0.69		0.04	5.73		5.08	−1.51		−2.15
1891–1900	0.18	5.08	4.40	4.49		4.75	8.89		9.15	3.81		4.08
1901–1910	1.95	3.18	4.45	3.25		2.33	7.70		6.78	4.52		3.60
1911–1920	6.82	0.82	5.70	−3.43		−6.52	2.27		−0.83	1.45		−1.64
1921–1930	−1.70	7.41	5.72	9.07		11.83	14.78		17.54	7.37		10.13
1931–1940	−1.23	2.80	5.31	0.36		2.21	5.67		7.52	2.87		4.72
1941–1950	6.04	−4.57	5.90	3.02		2.33	8.91		8.22	13.48		12.79
1951–1960	1.79	1.05	4.68	1.22		10.64	5.90		15.32	4.85		14.27
1961–1970	2.94	2.27	3.21	1.98		2.69	5.19		5.90	2.92		3.63
1971–1980	8.11	−0.30	4.04	−0.86		−1.92	3.18		2.12	3.48		2.42
1981–1990	4.51	5.32	4.19	2.32		5.40	6.51		9.59	1.19		4.28
1991–2000	2.68	2.61	2.36	0.58		12.80	2.94		15.16	0.32		12.54

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Table III

Regressions to Forecast Real Dividend and Earnings Growth Rates, GD_t and GY_t

The price level at the end of year t is L_t. The nominal values of book equity and price for the S&P index at the end of year t are b_t and p_t. Nominal S&P dividends and earnings for year t are d_t and y_t. The real dividend and earnings growth rates for year t are $GD_t = (d_t/d_{t-1})*(L_{t-1}/L_t) - 1$ and $GY_t = (y_t/y_{t-1})*(L_{t-1}/L_t) - 1$, and R_t is the realized real return on the S&P portfolio for year t. The regression intercept is *Int*, and t-Stat is the regression coefficient (*Coef*) divided by its standard error. The regression R^2 is adjusted for degrees of freedom. Except for the dividend payout ratio, d_t/y_t, all variables are expressed as percents, that is, they are multiplied by 100.

Panel A: One Year: The Regressions Forecast Real Dividend Growth, GD_t, with Variables Known at $t - 1$

	Int	d_{t-1}/y_{t-1}	d_{t-1}/p_{t-1}	GD_{t-1}	GD_{t-2}	GD_{t-3}	R_{t-1}	R_{t-2}	R_{t-3}	R^2
1875–1950, N = 76 years										
Coef	29.56	−23.12	−2.63	−0.12	−0.07	−0.03	0.22	0.13	0.09	0.38
t-Stat	3.22	−3.17	−1.77	−1.08	−0.64	−0.29	2.24	1.37	1.01	
1951–2000, N = 50 years										
Coef	−2.16	2.97	0.11	−0.07	−0.20	−0.06	0.11	0.07	0.01	0.01
t-Stat	−0.40	0.33	0.16	−0.45	−1.57	−0.45	2.17	1.33	0.22	

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Panel B: Two Years: The Regressions Forecast Real Dividend Growth, GD_t, with Variables Known at $t - 2$

	Int	d_{t-2}/y_{t-2}	d_{t-2}/p_{t-2}	GD_{t-2}	GD_{t-3}	R_{t-2}	R_{t-3}	R^2
1875–1950, N = 76 years								
Coef	6.61	−11.60	0.31	−0.26	0.05	0.24	0.11	0.07
t-Stat	0.64	−1.28	0.18	−2.02	0.39	2.03	1.00	
1951–2000, N = 50 years								
Coef	−4.11	7.62	0.32	−0.14	−0.03	0.05	−0.01	−0.05
t-Stat	−0.73	0.81	0.46	−1.13	−0.28	0.99	−0.16	

Panel C: One Year: The Regressions Forecast Real Earnings Growth, GY_t, with Variables Known at $t - 1$

	Int	Y_{t-1}/B_{t-2}	d_{t-1}/y_{t-1}	y_{t-1}/p_{t-1}	GY_{t-1}	GY_{t-2}	GY_{t-3}	R_{t-1}	R_{t-2}	R_{t-3}	R^2
1951–2000, N = 50 years											
Coef	5.48	0.11	13.06	−1.36	0.21	−0.13	−0.31	0.28	−0.25	0.03	0.40
t-Stat	0.33	0.11	0.52	−1.91	1.17	−0.89	−2.64	2.39	−2.18	0.26	

Panel D: Two Years: The Regressions Forecast Real Earnings Growth, GY_t, with Variables Known at $t - 2$

	Int	Y_{t-2}/B_{t-3}	d_{t-2}/y_{t-2}	y_{t-2}/p_{t-2}	GY_{t-2}	GY_{t-3}	R_{t-2}	R_{t-3}	R^2
1951–2000, N = 50 years									
Coef	−7.60	0.46	2.05	−0.74	−0.16	−0.39	−0.31	−0.12	0.23
t-Stat	−0.43	1.66	0.76	−1.02	−0.92	−2.54	−2.59	−0.97	

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gressions are shown for forecasts one year ahead (the explanatory variables for year t dividend growth are known at the end of year $t - 1$) and two years ahead (the explanatory variables are known at the end of year $t - 2$).

The regression for 1875 to 1950 suggests strong forecast power one year ahead. The slopes on the lagged payout ratio, the dividend–price ratio, and the stock return are close to or more than two standard errors from zero, and the regression captures 38 percent of the variance of dividend growth. Even in the 1875 to 1950 period, however, power to forecast dividend growth does not extend much beyond a year. When dividend growth for year t is explained with variables known at the end of year $t - 2$, the regression R^2 falls from 0.38 to 0.07. Without showing the details, we can report that extending the forecast horizon from two to three years causes all hint of forecast power to disappear. Thus, for 1875 to 1950, the best forecast of dividend growth more than a year or two ahead is the historical average growth rate.

We are interested in post-2000 expected dividend growth, and even the short-term forecast power of the dividend regressions for 1872 to 1950 evaporates in the 1951 to 2000 period. The lagged stock return has some information ($t = 2.17$) about dividend growth one year ahead. But the 1951 to 2000 regression picks up only one percent of the variance of dividend growth. And forecast power does not improve for longer forecast horizons. Our evidence that dividend growth is essentially unpredictable during the last 50 years confirms the results in Campbell (1991), Cochrane (1991, 1994), and Campbell and Shiller (1998). If dividend growth is unpredictable, the historical average growth rate is the best forecast of future growth.

Long-term expected earnings growth also is not unusually high in 2000. There is no clear trend in real earnings growth during the 1951 to 2000 period. The most recent decade, 1991 to 2000, produces the highest average growth rate, 7.58 percent per year (Table II). But earnings growth is volatile. The standard errors of 10-year average growth rates vary around 5 percent. It is thus not surprising that 1981 to 1990, the decade immediately preceding 1991 to 2000, produces the lowest average real earnings growth rate, 0.37 percent per year.

The regressions in Table III are formal evidence on the predictability of earnings growth during the 1951 to 2000 period. There is some predictability of near-term growth, but it is largely due to transitory variation in earnings that is irrelevant for forecasting long-term earnings. In the 1951 to 2000 regression to forecast earnings growth one year ahead, the slope on the first lag of the stock return is positive (0.28, $t = 2.39$), but the slope on the second lag is negative (-0.25, $t = -2.18$) and about the same magnitude. Thus, the prediction of next year's earnings growth from this year's return is reversed the following year. In the one-year forecast regression for 1951 to 2000, the only variable other than lagged returns with power to forecast earnings growth ($t = -2.64$) is the third lag of earnings growth. But the slope is negative, so it predicts that the strong earnings growth of recent years is soon to be reversed.

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In the 1951 to 2000 regression to forecast earnings one year ahead, there is a hint ($t = -1.91$) that the low earnings–price ratio at the end of the period implies higher than average expected growth one year ahead. But the effect peters out quickly; the slope on the lagged earnings–price ratio in the regression to forecast earnings growth two years ahead is -1.02 standard errors from zero. The only variables with forecast power two years ahead are the second lag of the stock return and the third lag of earnings growth. But the slopes on these variables are negative, so again the 2000 prediction is that the strong earnings growth of recent years is soon to be reversed. And again, regressions (not shown) confirm that forecast power for 1951 to 2000 does not extend beyond two years. Thus, beyond two years, the best forecast of earnings growth is the historical average growth rate.

In sum, the behavior of dividends for 1951 to 2000 suggests that future growth is largely unpredictable, so the historical mean growth rate is a near optimal forecast of future growth. Earnings growth for 1951 to 2000 is somewhat predictable one and two years ahead, but the end-of-sample message is that the recent high growth rates are likely to revert quickly to the historical mean. It is also worth noting that the market survivor bias argument of Brown, Goetzmann, and Ross (1995) suggests that past average growth rates are, if anything, upward biased estimates of future growth. In short, we find no evidence to support a forecast of strong future dividend or earnings growth at the end of our sample period.

C. Do Expected Stock Returns Fall during the 1951 to 2000 Period?

The S&P dividend–price ratio, D_t/P_t, falls from 7.18 percent at the end of 1950 to a historically low 1.22 percent at the end of 2000 (Figure 1). The growth in the stock price, P_{2000}/P_{1950}, is thus 5.89 times the growth in dividends, D_{2000}/D_{1950}. The S&P earnings–price ratio, Y_t/P_t, falls from 13.39 percent at the end of 1950 to 3.46 percent at the end of 2000, so the percent capital gain of the last 50 years is 3.87 times the percent growth in earnings. (Interestingly, almost all of the excess capital gain occurs in the last 20 years; Figure 1 shows that the 1979 earnings–price ratio, 13.40 percent, is nearly identical to the 13.39 percent value of 1950.)

All valuation models say that D_t/P_t and E_t/P_t are driven by expected future returns (discount rates) and expectations about future dividend and earnings growth. Our evidence suggests that rational forecasts of long-term dividend and earnings growth rates are not unusually high in 2000. We conclude that the large spread of capital gains for 1951 to 2000 over dividend and earnings growth is largely due to a decline in the expected stock return.

Some of the decline in D_t/P_t and E_t/P_t during 1951 to 2000 is probably anticipated in 1950. The dividend–price ratio for 1950, 7.18 percent, is high (Figure 1). The average for 1872 to 2000 is 4.64 percent. If D_t/P_t is mean-reverting, the expectation in 1950 of the yield in 2000 is close to the unconditional mean, say 4.64 percent. The actual dividend–price ratio for 2000 is

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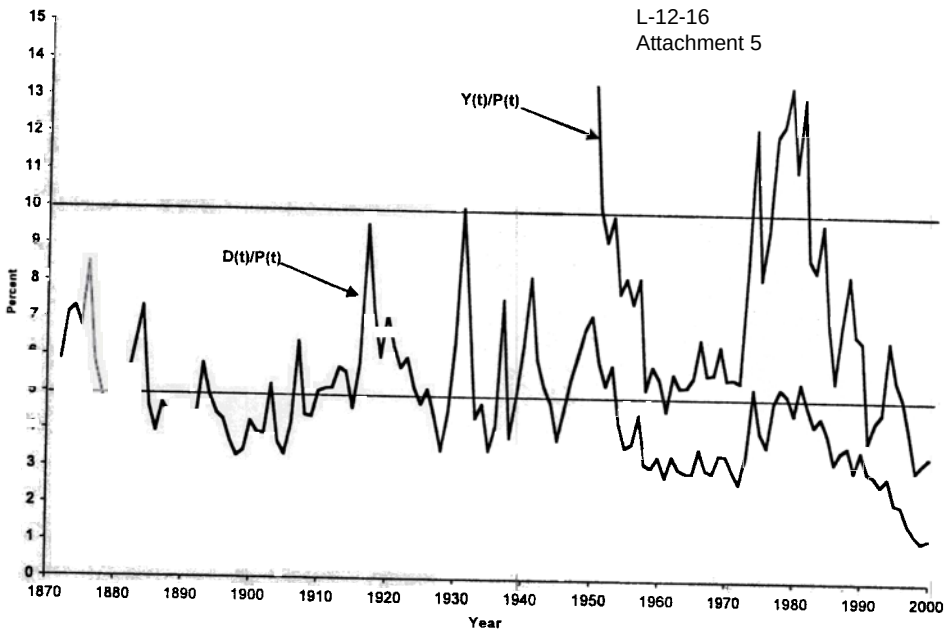

Figure 1. Dividend–price and earnings–price ratios.

1.22 percent. The 2000 stock price is thus 4.64/1.22 = 3.80 times what it would be if the dividend yield for 2000 hit the historical mean. Roughly speaking, this unexpected capital gain adds about 2.67 percent to the compound annual return for 1951 to 2000.

Similarly, part of the large difference between the 1951 to 2000 capital gain and the growth in earnings is probably anticipated in 1950. The 13.39 percent value of Y_t/P_t in 1950 is high relative to the mean for 1951 to 2000, 7.14 percent. If the earnings–price ratio is stationary, the expectation in 1950 of Y_t/P_t for 2000 is close to the unconditional mean, say 7.14 percent. The actual Y_t/P_t for 2000 is 3.46 percent. Thus, the 2000 stock price is 7.14/3.46 = 2.06 times what it would be if the ratio for 2000 hit the 7.14 percent average value for 1951 to 2000. Roughly speaking, this estimate of the unexpected capital gain adds about 1.45 percent to the compound annual return for the 50-year period.

In short, the percent capital gain for 1951 to 2000 is several times the growth of dividends or earnings. The result is historically low dividend–price and earnings–price ratios at the end of the period. Since the ratios are high in 1950, some of their subsequent decline is probably expected, but much of it is unexpected. Given the evidence that rational forecasts of long-term growth rates of dividends and earnings are not high in 2000, we conclude that the unexpected capital gains for 1951 to 2000 are largely due to a decline in the discount rate. In other words, the low end-of-sample price ratios imply low (rationally assessed, or true) expected future returns.

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Like us, Campbell (1991), Cochrane (1994), and Campbell and Shiller (1998) find that, for recent periods, dividend and earnings growth are largely unpredictable, so variation in dividend–price and earnings–price ratios is largely due to the expected stock return. The samples in Campbell (1991) and Cochrane (1994) end in 1988 (before the strong subsequent returns that produce sharp declines in the price ratios), and they focus on explaining, in general terms, how variation in D_t/P_t splits between variation in the expected stock return and expected dividend growth. Campbell and Shiller (1998) focus on the low expected future returns implied by the low price ratios of recent years.

In contrast, we are more interested in what the decline in the price ratios says about past returns, specifically, that the average return for 1951 to 2000 is above the expected return. And this inference does not rest solely on the information in price ratios. We buttress it with two types of novel evidence. (a) The perspective from our long sample period that, although the average stock return for 1951 to 2000 is much higher than expected return estimates from fundamentals, the two approaches produce similar estimates for 1872 to 1950. (b) Evidence from Sharpe ratios, the book-to-market ratio, and the income return on investment, which also suggests that the average return for 1951 to 2000 is above the expected value.

III. Estimating the Expected Stock Return: Issues

There are two open questions about our estimates of the expected stock return. (a) In recent years the propensity of firms to pay dividends declines and stock repurchases surge. How do these changes in dividend policy affect our estimates of the expected return? (b) Under rather general conditions, the dividend and earnings growth models (2) and (3) provide estimates of the expected stock return. Are the estimates biased and does the bias depend on the return horizon? This section addresses these issues.

A. Repurchases and the Declining Incidence of Dividend Payers

Share repurchases surge after 1983 (Bagwell and Shoven (1989) and Dunsby (1995)), and, after 1978, the fraction of firms that do not pay dividends steadily increases (Fama and French (2001)). More generally, dividends are a policy variable, and changes in policy can raise problems for estimates of the expected stock return from the dividend growth model. There is no problem in the long-term, as long as dividend policies stabilize and the dividend–price ratio resumes its mean-reversion, though perhaps to a new mean. (An Appendix, available on request, provides an example involving repurchases.) But there can be problems during transition periods. For example, if the fraction of firms that do not pay dividends steadily increases, the market dividend–price ratio is probably nonstationary; it is likely to decline over time, and the dividend growth model is likely to underestimate the expected stock return.

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Fortunately, the earnings growth model is not subject to the problems posed by drift in dividend policy. The earnings growth model provides an estimate of the expected stock return when the earnings–price ratio is stationary. And as discussed earlier, the model provides an estimate of the average expected return during the sample period when there are permanent shifts in the expected value of Y_t/P_t, as long as the ratio mean-reverts within regimes.

The earnings growth model is not, however, clearly superior to the dividend growth model. The standard deviation of annual earnings growth rates for 1951 to 2000 (13.79 percent, versus 5.09 percent for dividends) is similar to that of capital gains (16.77 percent), so much of the precision advantage of using fundamentals to estimate the expected stock return is lost. We see next that the dividend growth model has an advantage over the earnings growth model and the average stock return if the goal is to estimate the long-term expected growth of wealth.

B. The Investment Horizon

The return concept in discrete time asset pricing models is a one-period simple return, and our empirical work focuses on the one-year return. But many, if not most, investors are concerned with long-term returns, that is, terminal wealth over a long holding period. Do the advantages and disadvantages of different expected return estimates depend on the return horizon? This section addresses this question.

B.1. The Expected Annual Simple Return

There is downward bias in the estimates of the expected annual simple return from the dividend and earnings growth models—the result of a variance effect. The expected value of the dividend growth estimate of the expected return, for example, is the expected value of the dividend yield plus the expected value of the annual simple dividend growth rate. The expected annual simple return is the expected value of the dividend yield plus the expected annual simple rate of capital gain. If the dividend–price ratio is stationary, the compound rate of capital gain converges to the compound dividend growth rate as the sample period increases. But because the dividend growth rate is less volatile than the rate of capital gain, the expected simple dividend growth rate is less than the expected simple rate of capital gain.

The standard deviation of the annual simple rate of capital gain for 1951 to 2000 is 3.29 times the standard deviation of the annual dividend growth rate (Table I). The resulting downward bias of the average dividend growth rate as an estimate of the expected annual simple rate of capital gain is roughly 1.28 percent per year (half the difference between the variances of the two growth rates). Corrected for this bias, the dividend growth estimate of the equity premium in the simple returns of 1951 to 2000 rises from 2.55 to 3.83 percent (Table IV), which is still far below the estimate from the average return, 7.43 percent. Since the earnings growth rate and the annual rate of capital gain have similar standard deviations for 1951 to 2000,

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Table IV

Estimates of the Real Equity Premium in Simple Annual and Long-term Returns: 1951 to 2000

The inflation rate for year t is $Inf_t = L_t/L_{t-1}$, where L_t is the price level at the end of year t. The real return for year t on six-month (three-month for the year 2000) commercial paper (rolled over at midyear) is F_t. The nominal value of the S&P index at the end of year t is p_t. Nominal S&P dividends and earnings for year t are d_t and y_t. Real rates of growth of dividends, earnings, and the stock price are $GD_t = (d_t/d_{t-1})*(L_{t-1}/L_t) - 1$, $GY_t = (y_t/y_{t-1})*(L_{t-1}/L_t) - 1$, and $GP_t = (p_t/p_{t-1})*(L_{t-1}/L_t) - 1$. The real dividend yield is $D_t/P_{t-1} = (d_t/p_{t-1})*(L_{t-1}/L_t)$. The dividend growth estimate of the real S&P return for t is $RD_t = D_t/P_{t-1} + GD_t$, the earnings growth estimate is $RY_t = D_t/P_{t-1} + GY_t$, and R_t is the realized real S&P return. The dividend and earnings growth estimates of the real equity premium for year t are $RXD_t = RD_t - F_t$ and $RXY_t = RY_t - F_t$, and $RX_t = R_t - F_t$ is the real equity premium from the realized real return. The average values of the equity premium estimates are $A(RXD_t)$, $A(RXY_t)$, and $A(RX_t)$. The first column of the table shows unadjusted estimates of the annual simple equity premium. The second column shows bias-adjusted estimates of the annual premium. The bias adjustment is one-half the difference between the variance of the annual rate of capital gain and the variance of either the dividend growth rate or the earnings growth rate. The third column shows bias-adjusted estimates of the expected equity premium relevant if one is interested in the long-term growth rate of wealth. The bias adjustment is one-half the difference between the variance of the annual dividend growth rate and the variance of either the growth rate of earnings or the rate of capital gain. The equity premiums are expressed as percents.

		Bias-adjusted	
	Unadjusted	Annual	Long-term
$A(RXD_t)$		3.83	
$A(RXY_t)$		4.78	
$A(RX_t)$		7.43	

13.79 percent and 16.77 percent (Table I), the bias of the earnings growth estimate of the expected return is smaller (0.46 percent). Corrected for bias, the estimate of the equity premium for 1951 to 2000 from the earnings growth model rises from 4.32 to 4.78 percent (Table IV), which again is far below the 7.43 percent estimate from the average return.

B.2. Long-term Expected Wealth

The (unadjusted) estimate of the expected annual simple return from the dividend growth model is probably the best choice if we are concerned with the long-term expected wealth generated by the market portfolio. The annual dividend growth rates of 1951 to 2000 are essentially unpredictable. If the dividend growth rate is serially uncorrelated, the expected value of the compounded dividend growth rate is the compounded expected simple growth rate:

$$E\left[\prod_{t=1}^{T}(1 + GD_t)\right] = [1 + E(GD)]^T. \tag{5}$$

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And if the dividend–price ratio is stationary, for long horizons the expected compounded dividend growth rate is the expected compounded rate of capital gain:

$$E\left[\prod_{t=1}^{T}(1+GD_t)\right] = E\left[\prod_{t=1}^{T}(1+GP_t)\right]. \tag{6}$$

Thus, when the horizon T is long, compounding the true expected annual simple return from the dividend growth model produces an unbiased estimate of the expected long-term return:

$$[1+E(RD)]^T = E\left[\prod_{t=1}^{T}(1+R_t)\right]. \tag{7}$$

In contrast, if the dividend growth rate is unpredictable and the dividend–price ratio is stationary, part of the higher volatility of annual rates of capital gain is transitory, the result of a mean-reverting expected annual return (Cochrane (1994)). Thus, compounding even the true unconditional expected annual simple return, $E(R)$, yields an upward biased measure of the expected compounded return:

$$[1+E(R)]^T > E\left[\prod_{t=1}^{T}(1+R_t)\right] \tag{8}$$

There is a similar problem in using the average (simple) earnings growth rate to estimate long-term expected wealth. The regressions in Table III suggest that the predictability of earnings growth for 1951 to 2000 is due to transitory variation in earnings. As a result, annual earnings growth is 2.71 times more volatile than dividend growth (Table I). The compound growth rate of earnings for 1951 to 2000, 1.89 percent, is 2.05 times the compound dividend growth rate, 0.92 percent. But because earnings are more volatile, the average simple growth rate of earnings, 2.82 percent, is 2.69 times the average simple growth rate of dividends, 1.05 percent. As a result, the average simple growth rate of earnings produces an upward biased estimate of the compound rate of growth of long-term expected wealth.

We can correct the bias by subtracting half the difference between the variance of earnings growth and the variance of dividend growth (0.82 percent) from the average earnings growth rate. The estimate of the expected rate of capital gain provided by this adjusted average growth rate of earnings is 2.00 percent per year. Using this adjusted average growth rate of earnings, the earnings growth estimate of the expected real stock return for 1951 to 2000 falls from 6.51 to 5.69 percent. The estimate of the equity premium falls from 4.32 to 3.50 percent (Table IV), which is closer to the 2.55 percent obtained when the average dividend growth rate is used to

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estimate the expected rate of capital gain. Similarly, adjusting for the effects of transitory return volatility causes the estimate of the equity premium from realized stock returns to fall from 7.43 to 6.16 percent, which is still far above the bias-adjusted estimate of the earnings growth model (3.50 percent) and the estimate from the dividend growth model (2.55 percent).

Finally, we only have estimates of the expected growth rates of dividends and earnings and the expected rate of capital gain. Compounding estimates rather than true expected values adds upward bias to measures of expected long-term wealth (Blume (1974)). The bias increases with the imprecision of the estimates. This is another reason to favor the more precise estimate of the expected stock return from the dividend growth model over the earnings growth estimate or the estimate from the average stock return.

IV. Conclusions

There is a burgeoning literature on the equity premium. Our main additions are on two fronts. (a) A long (1872 to 2000) perspective on the competing estimates of the unconditional expected stock return from fundamentals (the dividend and earnings growth models) and the average stock return. (b) Evidence (estimates of precision, Sharpe ratios, and the behavior of the book-to-market ratio and the income return on investment) that allows us to choose between the expected return estimates from the two approaches.

Specifically, the dividend growth model and the realized average return produce similar real equity premium estimates for 1872 to 1950, 4.17 percent and 4.40 percent. For the half-century from 1951 to 2000, however, the equity premium estimates from the dividend and earnings growth models, 2.55 percent and 4.32 percent, are far below the estimate from the average return, 7.43 percent.

We argue that the dividend and earnings growth estimates of the equity premium for 1951 to 2000 are closer to the true expected value. This conclusion is based on three results.

(a) The estimates from fundamentals, especially the estimate from the dividend growth model, are more precise; they have lower standard errors than the estimate from the average return.

(b) The appealing message from the dividend and earnings growth models is that aggregate risk aversion (as measured by the Sharpe ratio for the equity premium) is on average roughly similar for the 1872 to 1949 and 1950 to 1999 periods. In contrast, the Sharpe ratio for the equity premium from the average return just about doubles from the 1872 to 1950 period to the 1951 to 2000 period.

(c) Most important, the average stock return for 1951 to 2000 is much greater than the average income return on book equity. Taken at face value, this says that investment during the period is on average unprofitable (its expected return is less than the cost of capital). In contrast, the lower estimates of the expected stock return from the dividend and earnings growth models are less than the income return on investment, so the message is

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that investment is on average profitable. This is more consistent with book-to-market ratios that are rather consistently less than one during the period.

If the average stock return for 1951 to 2000 exceeds the expected return, stocks experience unexpected capital gains. What is the source of the gains? Growth rates of dividends and earnings are largely unpredictable, so there is no basis for extrapolating unusually high long-term future growth. This leaves a decline in the expected stock return as the prime source of the unexpected capital gain. In other words, the high return for 1951 to 2000 seems to be the result of low expected future returns.

Many papers suggest that the decline in the expected stock return is in part permanent, the result of (a) wider equity market participation by individuals and institutions, and (b) lower costs of obtaining diversified equity portfolios from mutual funds (Diamond (1999), Heaton and Lucas (1999), and Siegel (1999)). But there is also evidence that the expected stock return is slowly mean reverting (Fama and French (1989) and Cochrane (1994)). Moreover, there are two schools of thought on how to explain the variation in expected returns. Some attribute it to rational variation in response to macroeconomic factors (Fama and French (1989), Blanchard (1993), and Cochrane (1994)), while others judge that irrational swings in investor sentiment are the prime moving force (e.g., Shiller (1989)). Whatever the story for variation in the expected return, and whether it is temporary or partly permanent, the message from the low end-of-sample dividend–price and earnings–price ratios is that we face a period of low (true) expected returns.

Our main concern, however, is the unconditional expected stock return, not the end-of-sample conditional expected value. Here there are some nuances. If we are interested in the unconditional expected annual simple return, the estimates for 1951 to 2000 from fundamentals are downward biased. The bias is rather large when the average growth rate of dividends is used to estimate the expected rate of capital gain, but it is small for the average growth rate of earnings. On the other hand, if we are interested in the long-term expected growth of wealth, the dividend growth model is probably best, and the average stock return and the earnings growth estimate of the expected return are upward biased. But our bottom line inference does not depend on whether one is interested in the expected annual simple return or long-term expected wealth. In either case, the bias-adjusted expected return estimates for 1951 to 2000 from fundamentals are a lot (more than 2.6 percent per year) lower than bias-adjusted estimates from realized returns. (See Table IV.) Based on this and other evidence, our main message is that the unconditional expected equity premium of the last 50 years is probably far below the realized premium.

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Long-Run Stock Returns: Participating in the Real Economy

Roger G. Ibbotson and Peng Chen

In the study reported here, we estimated the forward-looking long-term equity risk premium by extrapolating the way it has participated in the real economy. We decomposed the 1926–2000 historical equity returns into supply factors—inflation, earnings, dividends, the P/E, the dividend-payout ratio, book value, return on equity, and GDP per capita. Key findings are the following. First, the growth in corporate productivity measured by earnings is in line with the growth of overall economic productivity. Second, P/E increases account for only a small portion of the total return of equity. The bulk of the return is attributable to dividend payments and nominal earnings growth (including inflation and real earnings growth). Third, the increase in the equity market relative to economic productivity can be more than fully attributed to the increase in the P/E. Fourth, a secular decline has occurred in the dividend yield and payout ratio, rendering dividend growth alone a poor measure of corporate profitability and future growth. Our forecast of the equity risk premium is only slightly lower than the pure historical return estimate. We estimate the expected long-term equity risk premium (relative to the long-term government bond yield) to be about 6 percentage points arithmetically and 4 percentage points geometrically.

Numerous authors are directing their efforts toward estimating expected returns on stocks incremental to bonds.[1] These equity risk premium studies can be categorized into four groups based on the approaches the authors took. The first group of studies has attempted to derive the equity risk premium from the historical returns of stocks and bonds; an example is Ibbotson and Sinquefield (1976a, 1976b). The second group, which includes our current work, has used fundamental information—such as earnings, dividends, or overall economic productivity—to measure the expected equity risk premium. The third group has adopted demand-side models that derive expected equity returns through the payoff demanded by investors for bearing the risk of equity investments, as in the Ibbotson, Diermeier, and Siegel (1984) demand framework and, especially, in the large body of literature following the seminal work of Mehra and Prescott (1985).[2] The fourth group has relied on opinions of investors and financial professionals garnered from broad surveys.

In the work reported here, we used supply-side models. We first used this type of model in Diermeier, Ibbotson, and Siegel (1984). Numerous other authors have used supply-side models, usually with a focus on the Gordon (1962) constant-dividend-growth model. For example, Siegel (1999) predicted that the equity risk premium will shrink in the future because of low current dividend yields and high equity valuations. Fama and French (2002), studying a longer time period (1872–1999), estimated a historical expected geometric equity risk premium of 2.55 percentage points when they used dividend growth rates and a premium of 4.32 percentage points when they used earnings growth rates.[3] They argued that the increase in the P/E has resulted in a realized equity risk premium that is higher than the *ex ante* (expected) premium. Campbell and Shiller (2001) forecasted low returns because they believe the current market is overvalued. Arnott and Ryan (2001) argued that the forward-looking equity risk premium is actually negative. This conclusion was based on the low

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current dividend yield plus their forecast for very low dividend growth. Arnott and Bernstein (2002) argued similarly that the forward-looking equity risk premium is near zero or negative (see also Arnott and Asness 2003).

The survey results generally support somewhat higher equity risk premiums. For example, Welch (2000) conducted a survey of 226 academic financial economists about their expectations for the equity risk premium. The survey showed that they forecasted a geometric long-horizon equity risk premium of almost 4 pps.[4] Graham and Harvey (2001) conducted a multiyear survey of chief financial officers of U.S. corporations and found their expected 10-year geometric average equity risk premium to range from 3.9 pps to 4.7 pps.[5]

In this study, we linked historical equity returns with factors commonly used to describe the aggregate equity market and overall economic productivity. Unlike some studies, ours portrays results on a per share basis (per capita in the case of GDP). The factors include inflation, EPS, dividends per share, P/E, the dividend-payout ratio, book value per share, return on equity, and GDP per capita.[6]

We first decomposed historical equity returns into various sets of components based on six methods. Then, we used each method to examine each of the components. Finally, we forecasted the equity risk premium through supply-side models using historical data.

Our long-term forecasts are consistent with the historical supply of U.S. capital market earnings and GDP per capita growth over the 1926–2000 period. In an important distinction from the forecasts of many others, our forecasts assume market efficiency and a constant equity risk premium.[7] Thus, the current high P/E represents the market's forecast of higher earnings growth rates. Furthermore, our forecasts are consistent with Miller and Modigliani (1961) theory, in that dividend-payout ratios do not affect P/Es and high earnings-retention rates (usually associated with low yields) imply higher per share future growth. To the extent that corporate cash is not used for reinvestment, we assumed it to be used to repurchase a company's own shares or, perhaps more frequently, to purchase other companies' shares. Finally, our forecasts treat inflation as a pass-through, so the entire analysis can be done in real terms.

Six Methods for Decomposing Returns

We present six different methods for decomposing historical equity returns. The first two methods (especially Method 1) are based entirely on historical returns. The other four methods are methods of the supply side. We evaluated each method and its components by applying historical data for 1926–2000. The historical equity return and EPS data used in this study were obtained from Wilson and Jones (2002).[8] The average compound annual return for the stock market over the 1926–2000 period was 10.70 percent. The arithmetic annual average return was 12.56 percent, and the standard deviation was 19.67 percent. Because our methods used geometric averages, we focus on the components of the 10.70 percent geometric return. When we present our forecasts, we convert the geometric average returns to arithmetic average returns.

Method 1. Building Blocks. Ibbotson and Sinquefield developed a "building blocks" model to explain equity returns. The three building blocks are inflation, the real risk-free rate, and the equity risk premium. Inflation is represented by changes in the U.S. Consumer Price Index (*CPI*). The equity risk premium for year t, ERP_t, and the real risk-free rate for year t, RRf_t, are given by, respectively,

$$ERP_t = \frac{1+R_t}{1+Rf_t} - 1 = \frac{R_t - Rf_t}{1+Rf_t} \quad (1)$$

and

$$RRf_t = \frac{1+Rf_t}{1+CPI_t} - \frac{Rf_t - CPI_t}{1+CPI_t}, \quad (2)$$

where R_t, the return of the U.S. stock market, represented by the S&P 500 Index, is

$$R_t = (1+CPI_t)(1+RRf_t)(1+ERP_t) - 1 \quad (3)$$

and Rf_t is the return of risk-free assets, represented by the income return of long-term U.S. government bonds.

The compound average for equity return was 10.70 percent for 1926–2000. For the equity risk premium, we can interpret that investors were compensated 5.24 pps a year for investing in common stocks rather than long-term risk-free assets (such as long-term U.S. government bonds). This calculation also shows that roughly half of the total historical equity return has come from the equity risk premium; the other half is from inflation and the long-term real risk-free rate. Average U.S. equity returns from 1926 through 2000 can be reconstructed as follows:[9]

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$$\bar{R} = (1+\overline{CPI})(1+\overline{RRf})(1+\overline{ERP})-1$$
$$10.70\% = (1+3.08\%)\times(1+2.05\%)\times(1+5.24\%)-1.$$

The first column in **Figure 1** shows the decomposition of historical equity returns for 1926–2000 according to the building blocks method.

Method 2. Capital Gain and Income. The equity return, based on the form in which the return is distributed, can be broken into capital gain, *cg*, and income return, *Inc*. Income return of common stock is distributed to investors through dividends, whereas capital gain is distributed through price appreciation. Real capital gain, *Rcg*, can be computed by subtracting inflation from capital gain. The equity return in period t can then be decomposed as follows:

$$R_t = [(1+CPI_t)(1+Rcg_t)-1]+Inc_t+Rinv_t, \quad (4)$$

where *Rinv* is reinvestment return.

The average income return was calculated to be 4.28 percent in the study period, the average capital gain was 6.19 percent, and the average real capital gain was 3.02 percent. The reinvestment return averaged 0.20 percent from 1926 through 2000. For Method 2, the average U.S. equity return for 1926–2000 can thus be computed according to

$$\bar{R} = [(1+\overline{CPI})(1+\overline{Rcg})-1]+\overline{Inc}+\overline{Rinv}$$
$$10.70\% = [(1+3.08\%)\times(1+3.02\%)-1]+4.28\%+0.20\%.$$

The second column in Figure 1 shows the decomposition of historical equity returns for 1926–2000 according to the capital gain and income method.

Method 3. Earnings. The real-capital-gain portion of the return in the capital gain and income method can be broken into growth in real EPS, g_{REPS}, and growth in P/E, $g_{P/E}$:

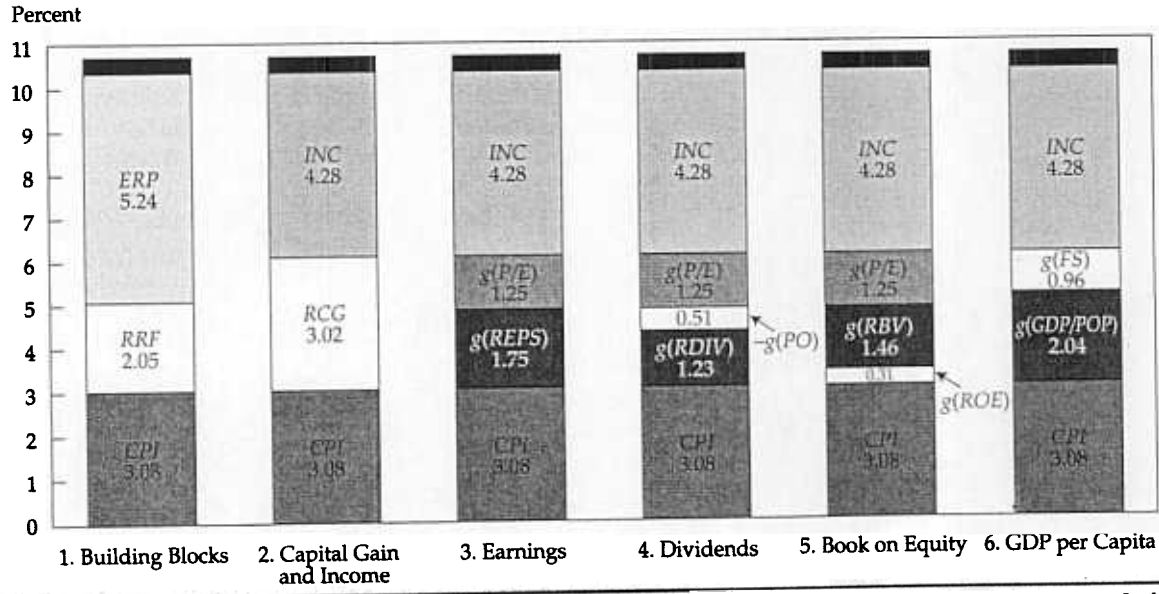
$$Rcg_t = \frac{P_t}{P_{t-1}}-1 = \frac{P_t/E_t}{P_{t-1}/E_{t-1}}\left(\frac{E_t}{E_{t-1}}\right) - = (1+g_{P/E,t})(1+g_{REPS,t})-1. \quad (5)$$

Therefore, equity's total return can be broken into four components—inflation, growth in real EPS, growth in P/E, and income return:

$$R_t = [(1+CPI_t)(1+g_{REPS,t})(1+g_{P/E,t})-1] + Inc_t + Rinv_t. \quad (6)$$

The real earnings of U.S. equity increased 1.75 percent annually between 1926 and 2000. The P/E, as **Figure 2** illustrates, was 10.22 at the beginning of 1926 and 25.96 at the end of 2000. The highest P/E (136.50 and off the chart in Figure 2) was recorded during the Great Depression, in December 1932, when earnings were near zero, and the lowest in the period (7.07) was recorded in 1948. The average year-end P/E was 13.76.[10]

Figure 1. Decomposition of Historical Equity Returns by Six Methods, 1926–2000



Notes: The block on the top of each column is the reinvestment return plus the geometric interactions among the components. Including the geometric interactions ensured that the components summed to 10.70 percent in this and subsequent figures. The table that constitutes Appendix A gives detailed information on the reinvestment and geometric interaction for all the methods.

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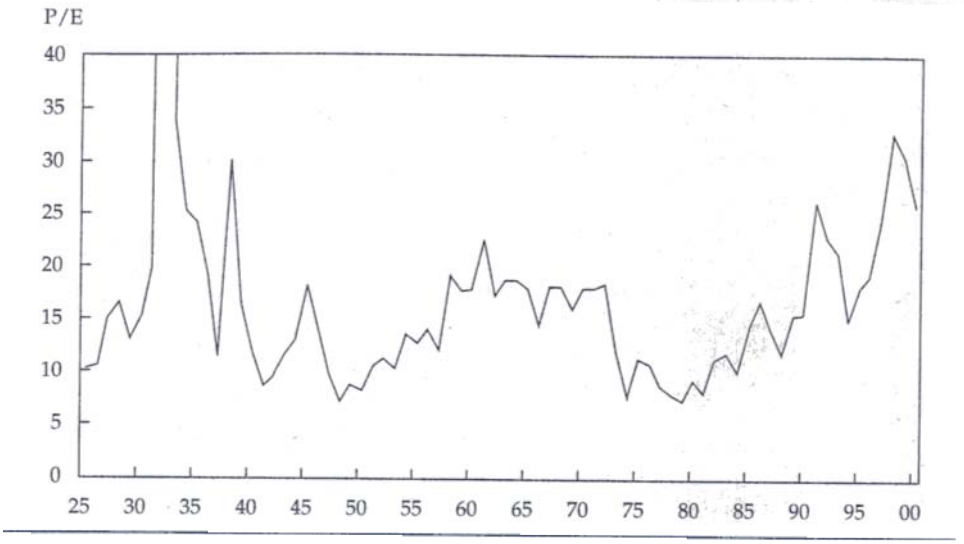
Figure 2. P/E, 1926–2000



The U.S. equity returns from 1926 and 2000 can be computed according to the earnings method as follows:

$$\bar{R} = [(1+\overline{CPI})(1+\overline{g_{REPS}})(1+\overline{g_{P/E}})-1] + \overline{Inc} + \overline{Rinv}$$

$$10.70\% = [(1+3.08\%)\times(1+1.75\%)\times(1+1.25\%)-1] + 4.28\% + 0.20\%.$$

The third column in Figure 1 shows the decomposition of historical equity returns for 1926–2000 according to the earnings method.

Method 4. Dividends. In this method, real dividends, *RDiv*, equal the real earnings times the dividend-payout ratio, *PO*, or

$$REPS_t = \frac{RDiv_t}{PO_t}; \quad (7)$$

therefore, the growth rate of earnings can be calculated by the difference between the growth rate of real dividends, g_{RDiv}, and the growth rate of the payout ratio, g_{PO}:

$$(1+g_{REPS,t}) = \frac{(1+g_{RDiv,t})}{(1+g_{PO,t})}. \quad (8)$$

If dividend growth and payout-ratio growth are substituted for the earnings growth in Equation 6, equity total return in period *t* can be broken into (1) inflation, (2) the growth rate of P/E, (3) the growth rate of the dollar amount of dividends after inflation, (4) the growth rate of the payout ratio, and (5) the dividend yield:

$$R_t = \left[(1+CPI_t)(1+g_{P/E,t})\left(\frac{1+g_{RDiv,t}}{1+g_{PO,t}}\right)-1\right] + Inc_t + Rinv_t. \quad (9)$$

Figure 3 shows the annual income return (dividend yield) of U.S. equity for 1926–2000. The dividend yield dropped from 5.15 percent at the beginning of 1926 to only 1.10 percent at the end of 2000. **Figure 4** shows the year-end dividend-payout ratio for 1926–2000. On average, the dollar amount of dividends after inflation grew 1.23 percent a year, while the dividend-payout ratio decreased 0.51 percent a year. The dividend-payout ratio was 46.68 percent at the beginning of 1926. It had decreased to 31.78 percent at the end of 2000. The highest dividend-payout ratio was recorded in 1932, and the lowest was the 31.78 percent recorded in 2000.

The U.S. equity returns from 1926 through 2000 can be computed in the dividends method according to

$$\bar{R} = \left[(1+\overline{CPI})(1+\overline{g_{P/E}})\left(\frac{1+\overline{g_{RDiv}}}{1+\overline{g_{PO}}}\right)-1\right] + \overline{Inc} + \overline{Rinv}$$

$$10.70\% = \left[(1+3.08\%)\times(1+1.25\%)\times\left(\frac{1+1.23\%}{1-0.51\%}\right)-1\right] + 4.28\% + 0.20\%.$$

The decomposition of equity return according to the dividends method is given in the fourth column of Figure 1.

Method 5. Return on Book Equity. Earnings can be broken into the book value of equity, *BV*, and return on the book value of equity, *ROE*:

$$EPS_t = BV_t(ROE_t). \quad (10)$$

The growth rate of earnings can be calculated from the combined growth rates of real book value, g_{RBV}, and of *ROE*:

$$1+g_{REPS,t} = (1+g_{RBV,t})(1+g_{ROE,t}). \quad (11)$$

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Figure 3. Income Return (Dividend Yield), 1926–2000

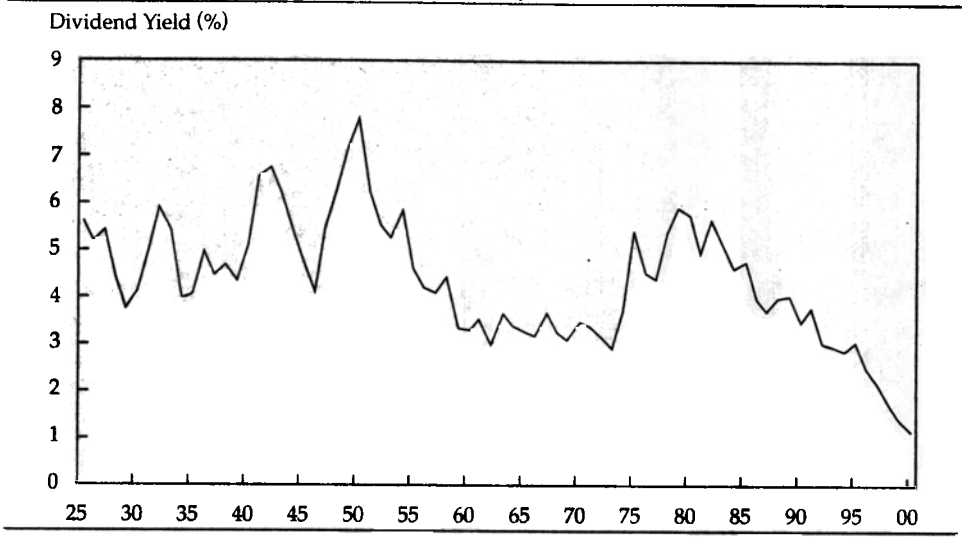
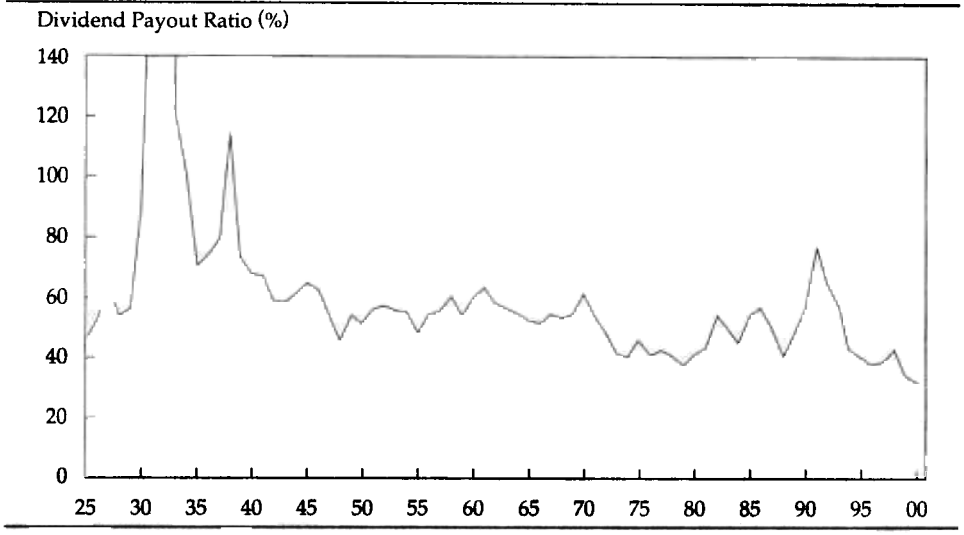


Figure 4. Dividend-Payout Ratio, Year-End 1926–2000



Note: The dividend-payout ratio was 190.52 percent in December 1931 and 929.12 percent in December 1932.

In this method, *BV* growth and *ROE* growth are substituted for earnings growth in the equity return decomposition, as shown in the fifth column of Figure 1. Then, equity's total return in period t can be computed by

$$R_t = [(1 + CPI_t)(1 + g_{P/E,t})(1 + g_{RBV,t})(1 + g_{ROE,t}) - 1] + Inc_t + Rinv_t. \quad (12)$$

We estimated that the average growth rate of the book value after inflation was 1.46 percent for 1926–2000.[11] The average *ROE* growth a year during the same time period was calculated to be 0.31 percent:

$$\bar{R} = [(1 + \overline{CPI})(1 + \overline{g_{P/E}})(1 + \overline{g_{BV}})(1 + \overline{g_{ROE}}) - 1] + \overline{Inc} + \overline{Rinv}$$

$$10.70\% = [(1 + 3.08\%)(1 + 1.25\%)(1 + 1.46\%)(1 + 0.31\%) - 1] + 4.28\% + 0.20\%.$$

Method 6. GDP per Capita. Diermeier et al. proposed a framework to analyze the aggregate supply of financial asset returns. Because we were interested only in the supply model of the equity returns in this study, we developed a slightly different supply model based on the growth of economic productivity. In this method, the market return over the long run is decomposed into (1)

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inflation, (2) the real growth rate of overall economic productivity (GDP per capita, $g_{GDP/POP}$), (3) the increase in the equity market relative to overall economic productivity (the increase in the factor share of equities in the overall economy, g_{FS}), and (4) dividend yields.[12] This model is expressed by the following equation:

$$R_t = [(1 + CPI_t)(1 + g_{GPD/POP,t})(1 + g_{FS,t}) - 1] + Inc_t + Rinv_t. \quad (13)$$

Figure 5 shows the growth of the U.S. stock market, GDP per capita, earnings, and dividends initialized to unity ($1.00) at the end of 1925. The level of all four factors dropped significantly in the early 1930s. For the whole period, GDP per capita slightly outgrew earnings and dividends, but all four factors grew at approximately the same rate. In other words, overall economic productivity increased slightly faster than corporate earnings or dividends over the past 75 years. Although GDP per capita outgrew earnings and dividends, the overall stock market price grew faster than GDP per capita. The primary reason is that the market P/E increased 2.54 times during the same time period.

Average equity market return can be calculated according to this model as follows:

$$\bar{R} = [(1 + \overline{CPI})(1 + \overline{g_{GDP/POP}})(1 + \overline{g_{FS}}) - 1] + \overline{Inc} + \overline{Rinv}$$

$$10.70\% = [(1 + 3.08\%)(1 + 2.04\%)(1 + 0.96\%) - 1] + 4.28\% + 0.20\%.$$

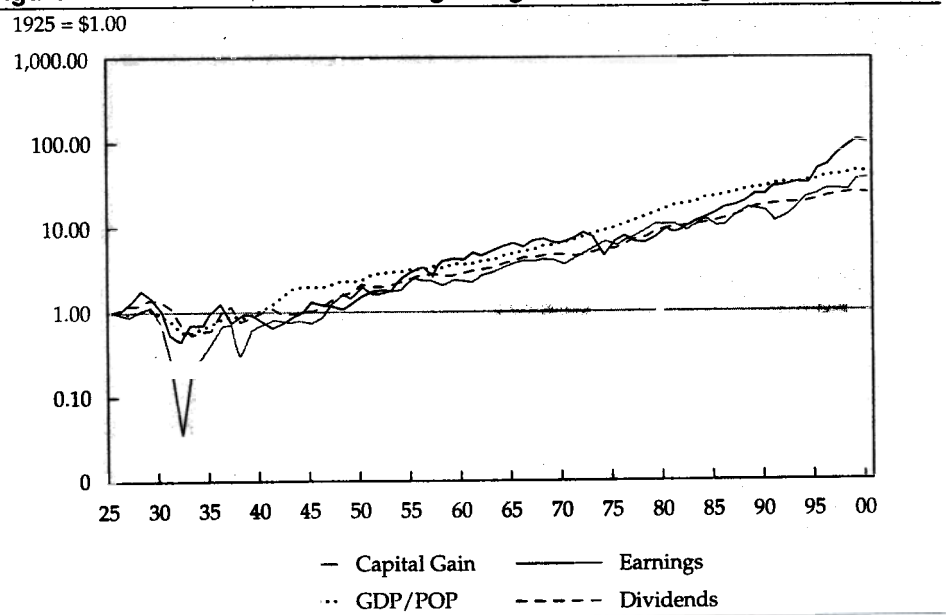
We calculated the average annual increase in the factor share of the equity market relative to the overall economy to be 0.96 percent. The increase in this factor share is less than the annual increase of the P/E (1.25 percent) over the same time period. This finding suggests that the increase in the equity market share relative to the overall economy can be fully attributed to the increase in its P/E.

The decomposition of historical equity returns by the GDP per capita model is given in the last column of Figure 1.

Summary of Equity Returns and Components. The decomposition of the six models into their components can be compared by looking at Figure 1. The differences among the five models arise from the different components that represent the capital gain portion of the equity returns.

This analysis produced several important findings. First, as Figure 5 shows, the growth in corporate earnings has been in line with the growth of overall economic productivity. Second, P/E increases accounted for only 1.25 pps of the 10.70 percent total equity return. Most of the return has been attributable to dividend payments and nominal earnings growth (including inflation and real earnings growth). Third, the increase in the relative factor share of equity can be fully attributed to the increase in P/E. Overall, economic productivity outgrew both corporate earnings and dividends from 1926 through 2000. Fourth, despite the record earnings growth in the 1990s, the dividend yield and the payout ratio declined sharply, which renders dividends alone a poor measure for corporate profitability and future earnings growth.

Figure 5. Growth of $1 from the Beginning of 1926 through 2000



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Long-Term Forecast of Equity Returns

Supply-side models can be used to forecast the long-term expected equity return. The supply of stock market returns is generated by the productivity of the corporations in the real economy. Over the long run, the equity return should be close to the long-run supply estimate. In other words, investors should not expect a much higher or a much lower return than that produced by the companies in the real economy. Therefore, we believe investors' expectations for long-term equity performance should be based on the supply of equity returns produced by corporations.

The supply of equity returns consists of two main components—current returns in the form of dividends and long-term productivity growth in the form of capital gains. In this section, we focus on two of the supply-side models—the earnings model and the dividends model (Methods 3 and 4).[13] We studied the components of these two models by identifying which components are tied to the supply of equity returns and which components are not. Then, we estimated the long-term, sustainable return based on historical information about these supply components.

Model 3F. Forward-Looking Earnings. According to the earnings model (Equation 6), the historical equity return can be broken into four components—the income return, inflation, the growth in real EPS, and the growth in P/E. Only the first three of these components are historically supplied by companies. The growth in P/E reflects investors' changing predictions of future earnings growth. Although we forecasted that the past supply of corporate growth will continue, we did not forecast any change in investor predictions. Thus, the supply side of equity return, *SR*, includes only inflation, the growth in real EPS, and income return:[14]

$$SR_t = [(1 + CPI_t)(1 + g_{REPS,t}) - 1] + Inc_t + Rinv_t. \quad (14)$$

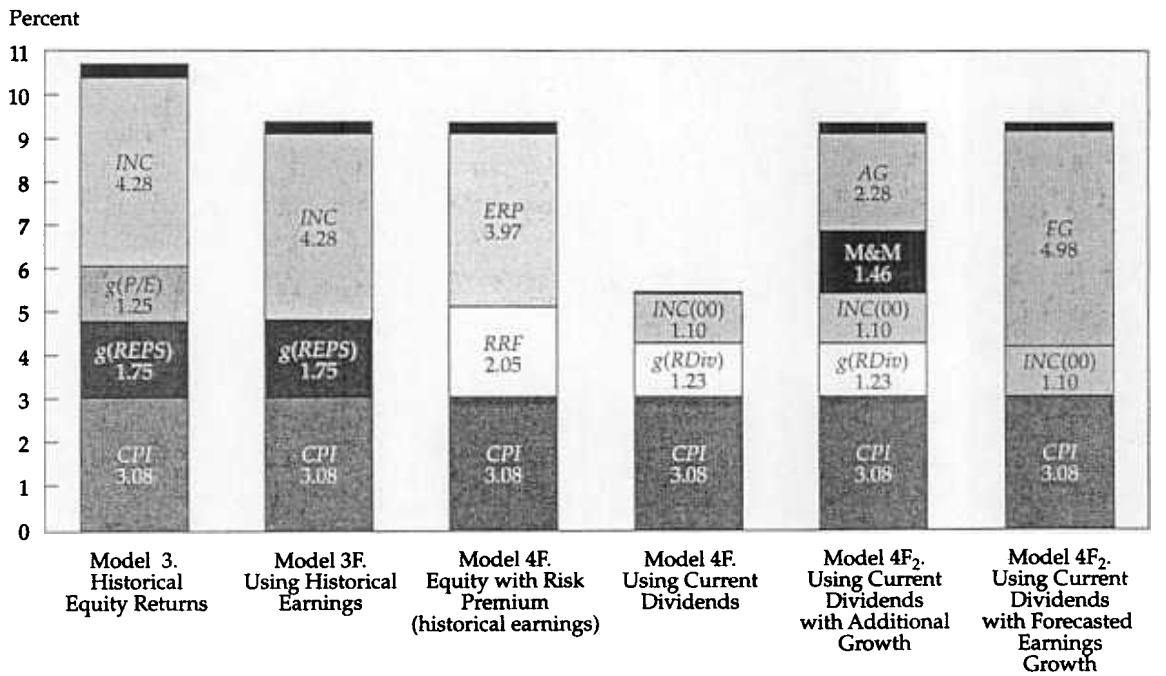
The long-term supply of U.S. equity returns based on the earnings model is 9.37 percent, calculated as follows:

$$\overline{SR} = [(1 + \overline{CPI})(1 + \overline{g_{REPS}}) - 1] + \overline{Inc} + \overline{Rinv}$$

$$9.37\% = [(1 + 3.08\%)(1 + 1.75\%) - 1] + 4.28\% + 0.20\%.$$

The decomposition according to Model 3F is compared with that of Method 3 (based on historical data plus the estimated equity risk premium) in the first two columns of **Figure 6**.

Figure 6. Historical vs. Current Dividend-Yield Forecasts Based on Earnings and Dividends Models



Notes: *Inc*(00) is the dividend yield in year 2000. *FG* is the real earnings growth rate, forecasted to be 4.98 percent. Model $4F_2$ corrects Model 4F as follows: add 1.46 pps for M&M consistency and add 2.24 pps for the additional growth, *AG*, implied by the high current market P/E.

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The supply-side equity risk premium, *ERP*, based on the earnings model is calculated to be 3.97 pps:

$$\overline{ERP} = \frac{(1+\overline{SR})}{(1+\overline{CPI})(1+\overline{RRf})} - 1$$
$$= \frac{1+9.37\%}{(1+3.08\%)(1+2.05\%)} - 1$$
$$= 3.97\%.$$

The *ERP* is taken into account in the third column of Figure 6.

Model 4F. Forward-Looking Dividends. The forward-looking dividends model is also referred to as the constant-dividend-growth model (or the Gordon model). In it, the expected equity return equals the dividend yield plus the expected dividend growth rate. The supply of the equity return in the Gordon model includes inflation, the growth in real dividends, and dividend yield.

As is commonly done with the constant-dividend-growth model, we used the current dividend yield of 1.10 percent instead of the historical dividend yield of 4.28 percent. This decision reduced the estimate of the supply of equity returns to 5.44 percent:

$$\overline{SR} = [(1+\overline{CPI})(1+\overline{g_{RDiv}})-1] + Inc(00) + \overline{Rinv}$$
$$5.54\% = [(1+3.08\%)(1+1.23\%)-1] + 1.10\% + 0.20\%,$$

where *Inc*(00) is the dividend yield in year 2000. The equity risk premium was estimated to be 0.24 pps:

$$\overline{ERP} = \frac{(1+\overline{SR})}{\quad}$$
$$= \frac{\quad}{(1+3.08\%)+(1+2.05\%)}$$
$$= 0.24\%.$$

Figure 6 allows a comparison of forecasted equity returns including the equity risk premium estimates based on the earnings model and the dividends model. In the next section, we show why we disagree with the dividends model and prefer to use the earnings model to estimate the supply-side equity risk premium.

Differences between the Earnings Model and the Dividends Model. The earnings model (3F) and the dividends model (4F) differ in essentially two ways. The differences relate to the low current payout ratio and the high current P/E. These two differences are reconciled in what we will call Model $4F_2$ shown in the two right-hand columns of Figure 6. First, to reflect growth in productivity, the earnings model uses historical earnings growth whereas the dividend model uses historical dividend growth. Historical dividend growth underestimates historical earnings growth, however, because of the decrease in the payout ratio. Overall, the dividend growth underestimated the increase in earnings productivity by 0.51 pps a year for 1926–2000. Today's low dividend yield also reflects the current payout ratio, which is at a historical low of 31.8 percent (compared with the historical average of 59.2 percent). Applying such a low rate to the future would mean that even more earnings would be retained in the future than in the historical period studied. But had more earnings been retained, the historical earnings growth would have been 0.95 pps a year higher, so (assuming the historical average dividend-payout ratio) the current yield of 1.10 percent would need to be adjusted upward by 0.95 pps.

By using the current dividend-payout ratio in the dividend model, Model 4F creates two errors, both of which violate Miller and Modigliani theory. A company's dividend-payout ratio affects only the form in which shareholders receive their returns (i.e., dividends versus capital gains), not their total returns. The *current* low dividend-payout ratio should not affect our forecast. Companies today probably have such low payout ratios to reduce the tax burden on their investors. Instead of paying dividends, many companies reinvest earnings, buy back shares, or use the cash to purchase other companies.[15] Therefore, the dividend growth model has to be upwardly adjusted by 1.46 pps (0.51 pp plus 0.95 pp) so as not to violate M&M theory.

The second difference between Model 3F and Model 4F is related to the fact that the current P/E (25.96) is much higher than the historical average (13.76). The current yield (1.10 percent) is at a historic low—because of the previously mentioned low payout ratio and because of the high P/E. Even assuming the historical average payout ratio, the current dividend yield would be much lower than its historical average (2.05 percent versus 4.28 percent). This difference is geometrically estimated to be 2.28 pps a year. In Figure 6, the additional growth, *AG*, accounts for 2.28 pps of the return; in the last column, the forecasted real earnings growth rate, *FG*, accounts for 4.98 pps. The high P/E could be caused by (1) mispricing, (2) a low required rate of return, and/or (3) a high expected future earnings growth rate. Mispricing as a cause is eliminated by our assumption of market efficiency, and a low required rate of return is eliminated by our assumption of a constant equity risk premium through the past and future periods that we are trying to estimate. Thus, we interpret the high P/E as the market expectation of higher earnings growth and the following equation is the model for

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Model $4F_2$, which reconciles the differences between the earnings model and the dividends model:[16]

$$\overline{SR} = [(1+\overline{CPI})(1+\overline{g_{RDiv}})(1-\overline{g_{PO}})-1] + Inc(00) + AY + AG + \overline{Rinv}$$

$$9.67\% = [(1+3.08\%)(1+1.23\%)(1+0.51\%)-1] + 1.10\% + 0.95\% + 2.28\% + 0.20\%.$$

To summarize, the earnings model and the dividends model have three differences. The first two differences relate to the dividend-payout ratio and are direct violations of M&M. The third difference results from the expectation of higher-than-average earnings growth, which is predicted by the high current P/E. Reconciling these differences reconciles the earnings and dividends models.

Geometric vs. Arithmetic. The estimated equity return (9.37 percent) and equity risk premium (3.97 pps) are geometric averages. The arithmetic average, however, is often used in portfolio optimization. One way to convert the geometric average into an arithmetic average is to assume the returns are independently lognormally distributed over time. Then, the arithmetic average, R_A, and geometric average, R_G, have roughly the following relationship:

$$R_A = R_G + \frac{\sigma^2}{2}, \quad (15)$$

where σ^2 is the variance.

The standard deviation of equity returns is 19.67 percent. Because almost all the variation in equity returns is from the equity risk premium, rather than the risk-free rate, we need to add 1.93 pps to the geometric estimate of the equity risk premium to convert the returns into arithmetic form, so $R_A = R_G + 1.93$ pps. The arithmetic average equity risk premium then becomes 5.90 pps for the earnings model.

To summarize, the long-term supply of equity return is estimated to be 9.37 percent (6.09 percent after inflation), conditional on the historical average risk-free rate. The supply-side equity risk premium is estimated to be 3.97 pps geometrically and 5.90 pps arithmetically.[17]

Conclusions

We adopted a supply-side approach to estimate the forward-looking, long-term, sustainable equity return and equity risk premium. We analyzed historical equity returns by decomposing returns into factors commonly used to describe the aggregate equity market and overall economic productivity—inflation, earnings, dividends, P/E, the dividend-payout ratio, BV, ROE, and GDP per capita. We examined each factor and its relationship to the long-term supply-side framework. We used historical information in our supply-side models to forecast the equity risk premium. A complete tabulation of all the numbers from all models and methods is presented in Appendix A.

Contrary to several recent studies on the equity risk premium declaring the forward-looking premium to be close to zero or negative, we found

Appendix A. Summary Tabulations for Forecasted Equity Return

Method/Model	Sum	Inflation	Real Risk-Free Rate	Equity Risk Premium	Real Capital Gain	*g*(Real *EPS*)	*g*(Real *Div*)	−*g*(Payout Ratio)
A. Historical								
Method 1	10.70	3.08	2.05	5.24				
Method 2	10.70	3.08			3.02			
Method 3	10.70	3.08				1.75		
Method 4	10.70	3.08					1.23	0.51
Method 5	10.70	3.08						
Method 6	10.70	3.08						
B. Forecast with historical dividend yield								
Model 3F	9.37	3.08				1.75		
Model 3F (*ERP*)	9.37	3.08	2.05	3.97				
C. Forecast with current dividend yield								
Model 4F	5.44	3.08					1.23	
Model 4F (*ERP*)	5.44	3.08	2.05	0.24				
Model $4F_2$	9.37	3.08					1.23	0.51
Model $4F_2$ (*FG*)	9.37	3.08						

[a]2000 dividend yield.
[b]Assuming the historical average dividend-payout ratio, the 2000 dividend yield is adjusted up 0.95 pps.

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the long-term supply of the equity risk premium to be only slightly lower than the straight historical estimate. We estimated the equity risk premium to be 3.97 pps in geometric terms and 5.90 pps on an arithmetic basis. These estimates are about 1.25 pps lower than the historical estimates. The differences between our estimates and the ones provided by several other recent studies result principally from the inappropriate assumptions those authors used, which violate the M&M theorem. Also, our models interpret the current high P/E as the market forecasting high future growth rather than a low discount rate or an overvaluation. Our estimate is in line with both the historical supply measures of public corporations (i.e., earnings) and overall economic productivity (GDP per capita).

The implication of an estimated equity risk premium being far closer to the historical premium than zero or negative is that stocks are expected to outperform bonds over the long run. For long-term investors, such as pension funds and individuals saving for retirement, stocks should continue to be a favored asset class in a diversified portfolio. Because our estimate of the equity risk premium is lower than historical performance, however, some investors should lower their equity allocations and/or increase their savings rate to meet future liabilities.

Notes

1. In our study, we defined the equity risk premium as the difference between the long-run expected return on stocks and the long-term risk-free (U.S. Treasury) yield. [Some other studies, including Ibbotson and Sinquefield (1976a, 1976b) used short-term U.S. T-bills as the risk-free rate.] We did all of our analysis in geometric form, then converted to arithmetic data at the end, so the estimate is expressed in both arithmetic and geometric forms.
2. See also Mehra (2003).
3. Comparing estimates from one study with another is sometimes difficult because of changing points of reference. The equity risk premium estimate can be significantly different simply because the authors used arithmetic versus geometric returns, a long-term risk-free rate versus a short-term risk-free rate, bond income return (yield) versus bond total return, or long-term strategic forecasting versus short-term market-timing estimates. We provide a detailed discussion of arithmetic versus geometric returns in the section "The Long-Term Forecast."
4. Welch's survey reported a 7 pp equity risk premium measured as the arithmetic difference between equity and T-bill returns. To make an apples-to-apples comparison, we converted the 7 pp number into a geometric equity risk premium relative to the long-term U.S. government bond income return, which produced an estimate of almost 4 pps.
5. For further discussion of approaches to estimating the equity risk premium, see the presentations and discussions at www.aimrpubs.org/ap/home.html from AIMR's *Equity Risk Premium Forum*.
6. Each per share quantity is per share of the S&P 500 portfolio. Hereafter, we will merely refer to each factor without always mentioning "per share"—for example, "dividends" instead of "dividends per share."
7. Many theoretical models suggest that the equity risk premium is dynamic over time. Recent empirical studies (e.g., Goyal and Welch 2001; Ang and Bekaert 2001) found no evidence, however, of long-horizon return predictability by using either earnings or dividend yields. Therefore, instead

g(BV)	*g(ROE)*	*g(P/E)*	*g*(Real *GDP/POP*)	*g(FS-GDP/POP)*	Income Return	Reinvestment + Interaction	Additional Growth	Forecasted Earnings Growth
						0.33		
					4.28	0.32		
		1.25			4.28	0.34		
		1.25			4.28	0.35		
.25	0.31	1.25			4.28	0.31		
			2.04	0.96	4.28	0.32		
					4.28	0.26		
						0.27		
					1.10[a]	0.03		
						0.07		
					2.05[b]	0.21	2.28	
					1.10[a]	0.21		4.98

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of trying to build a model for a dynamic equity risk premium, we assumed that the long-term equity risk premium is constant. This assumption provided a benchmark for analysis and discussion.

8. We updated the series with data from Standard and Poor's to include the year 2000.
9. Appendix A summarizes all the tabulations we discuss.
10. The average P/E was calculated by reversing the average earnings-to-price ratio for 1926–2000.
11. Book values were calculated from the book-to-market ratios reported in Vuolenteenaho (2000). The aggregate book-to-market ratio was 2.0 in 1928 and 4.1 in 1999. We used the growth rate in book value calculated for 1928–1999 as the proxy for the growth rate for 1926–2000. The average ROE growth rate was calculated from the derived book value and the earnings data.
12. Instead of assuming a constant equity factor share, we examined the historical growth rate of the equity factor share relative to the overall growth of the economy.
13. We did not use Methods 1, 2, and 5 in forecasting because the forecasts of Methods 1 and 2 would be identical to the historical estimate reported in the previous section and because the forecast of Method 5 would require more complete BV and ROE data than we currently have available. We did use Method 6 to forecast future stock returns but found the results to be very similar to those for the earnings model; therefore, we do not report the results here.
14. This model uses historical income return as an input for reasons that are discussed in the section "Differences between the Earnings Model and the Dividends Model."
15. The current tax code provides incentives for companies to distribute cash through share repurchases rather than through dividends. Green and Hollifield (2001) found that the tax savings through repurchases are on the order of 40–50 percent of the taxes that investors would have paid if dividends were distributed.
16. Contrary to efficient market models, Shiller (2000) and Campbell and Shiller argued that the P/E appears to forecast future stock price change.
17. We could also use the GDP per capita model to estimate the long-term equity risk premium. This model implies long-run stock returns should be in line with the productivity of the overall economy. The equity risk premium estimated by using the GDP per capita model would be slightly higher than the *ERP* estimate from the earnings model because GDP per capita grew slightly faster than corporate earnings in the study period. A similar approach can be found in Diermeier et al., who proposed using the growth rate of the overall economy as a proxy for the growth rate in aggregate wealth in the long run.

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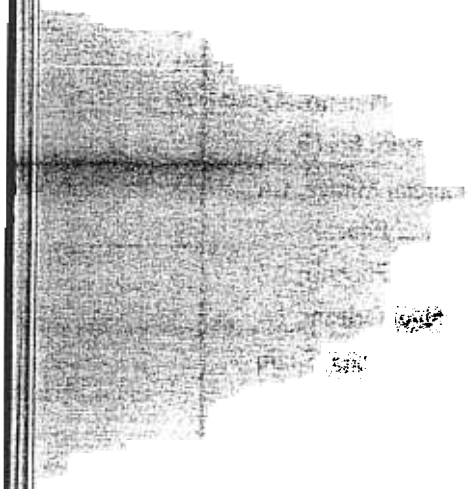
The Shrinking Equity Premium

Historical facts and future forecasts.

Jeremy J. Siegel



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Few conundrums have caught the imagination of economists and practitioners as much as the "Equity Premium Puzzle," the title chosen by Rajneesh Mehra and Edward Prescott for their seminal 1985 article in the *Journal of Monetary Economics*. Mehra and Prescott show that the historical return on stocks has been too high in relation to the return on risk-free assets to be explained by the standard economic models of risk and return without invoking unreasonably high levels of risk aversion.[1] They calculate the margin by which stocks outperformed safe assets — the *equity premium* — to be in excess of 6 percentage points per year, and claim that the profession is at a loss to explain its magnitude.

There have been many attempts since to explain the size of the equity premium by variations of the standard finance model. I shall not enumerate them here, but refer readers to reviews by Abel [1991], Kocherlakota [1996], Cochrane [1997], and Siegel and Thaler [1997].

I review here the estimates of the equity premium derived from historical data, and offer some reasons why I believe that most of the historical data underestimate the real return on fixed-income assets and overestimate the expected return on equities. I shall also offer some reasons why, given the current high level of the stock market relative to corporate earnings, the forward-looking equity premium may be considerably lower than the historical average.

REAL RETURNS ON "RISK-FREE" ASSETS

From 1889 through 1978, Mehra and Prescott estimate the real return on short-dated fixed-income

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assets (commercial paper until 1920 and Treasury bills thereafter) to have been 0.8%. In 1976 and again in 1982, Roger Ibbotson and Rex Sinquefield formally estimated the real risk-free rate to be even lower — at zero, based on historical data analyzed from 1926. This extremely low level of the short-term real rate is by itself puzzling, and has been termed the "real rate puzzle" by Weil [1989]. The essence of this puzzle is that, given the historical growth of per capita income, it is surprising that the demand to borrow against tomorrow's higher consumption has not resulted in higher borrowing rates.

The low measured level of the risk-free rate may in fact be in part an artifact of the time period examined. There is abundant evidence that the real rate both during the nineteenth century and after 1982 has been substantially higher. Exhibit 1, based on Siegel [1998], indicates that over the entire period from 1802 through 1998, the real compound annual return on Treasury bills (or equivalent safe assets) has been 2.9%, while the realized return on long-term government bonds has been 3.5%. Exhibit 2 presents the historical equity premium for selected time periods for both bonds and bills based on the same data.[2]

EXHIBIT 1
COMPOUND ANNUAL REAL RETURNS (%)
U.S. DATA, 1802-1998

	Stocks	Bonds	Bills	Gold	Inflation
1802-1998	7.0	3.5	2.9	–0.1	1.3
1802-1870	7.0	4.8	5.1	0.2	0.1
1871-1925	6.6	3.7	3.2	–0.8	0.6
1926-1998	7.4	2.2	0.7	0.2	3.1
1946-1998	7.8	1.3	0.6	–0.7	4.2

Source: Siegel [1998] updated.

The danger of using historical averages — even over long periods — to make forecasts is readily illustrated by noting Ibbotson and Sinquefield's long-term predictions made in 1976 and again in 1982 on the basis of their own analysis of the historical data. In 1976, they made predictions for the twenty-five-year period from

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EXHIBIT 2
EQUITY PREMIUMS (%) — U.S. DATA, 1802-1998

	Equity Premium with Bonds		Equity Premium with Bills	
	Geometric	Arithmetic	Geometric	Arithmetic
1802-1998	3.5	4.7	5.1	5.5
1802-1870	2.2	3.2	1.9	2.9
1871-1925	2.9	4.0	3.4	4.6
1926-1998	5.2	6.7	6.7	8.6
1946-1998	6.5	7.3	7.2	8.6

Source: Siegel [1998] updated.

1976 through 2000, and in 1982 they made predictions for the twenty-year period from 1982 through 2001. Their forecasts are shown in Exhibit 3. Since we now have data for most of these forecast periods, it is of interest to assess their estimates.

The last two decades have been extremely good for financial assets, so it is not surprising that Ibbotson and Sinquefield underestimate all their real returns. But their most serious underestimation is for fixed-income assets, where they forecast the real bill rate to average essentially zero and the real return on bonds to be less than 2%. Given the standard deviation of estimates, realized annual real bond and bill returns have been 9.9% and 2.9%, respectively, significantly above their estimates. Since negative real returns on fixed-income assets persisted between the two surveys, Ibbotson and Sinquefield more seriously underestimate long-term real bill rates in their 1982 forecasts than they did in 1976.[3]

My purpose here is not to highlight errors in Ibbotson's and Sinquefield's past forecasts. Their analysis was state-of-the-art, and their data have rightly formed the benchmark for the risk and return estimates used by both professional and academic economists. I bring these forecasts to light to show that even the fifty-year history of financial returns available to economists at that time was insufficient to estimate future real fixed-income returns.

It is not well understood why the real rate of returns on fixed-income assets was so low during the 1926-1980 period. The bursts of unanticipated inflation following the end of World War II and during the 1970s certainly had a negative effect on the realized real returns from long-term bonds. Perhaps the shift from a gold standard to a paper monetary standard had a negative effect on these real returns until investors fully adjusted to the inflationary bias inherent in the new monetary standard.[4]

Whatever the reasons, the current yields on the Treasury inflation-protected securities, or TIPS, first issued in 1997 support the assertion that the future real returns on risk-free assets will be substantially above the level estimated over the Ibbotson-Sinquefield period. This is so even when the estimating period includes the higher real rates of the past two decades. In August 1999, the ten- and thirty-year TIPS bond yielded 4.0%, nearly twice the realized rate of return on long-dated government bonds over the past seventy-five years.[5]

The market projects real returns on risk-free assets to be substantially higher in the future than they have been over most of this century. It is also likely that the expected returns in the past are substantially greater than they have turned out ex post, especially for longer-dated securities. If one uses a 3.5% real return on fixed-income assets, the geometric equity premium for a 7.0% real stock return falls to 3.5%.

EXHIBIT 3
LONG-TERM FORECASTS OF REAL RETURNS — COMPOUND ANNUAL RATES OF RETURN

Forecast Period		Stocks	Bonds	Bills	Inflation
1976-2000	Forecast	6.3 (23.5)	1.5 (8.0)	0.4 (4.6)	6.4 (4.8)
	Actual*	11.0	5.3	2.1	4.8
1982-2001	Forecast	7.6 (21.9)	1.8 (8.3)	0.0 (4.4)	12.8 (5.1)
	Actual*	14.6	9.9	2.9	3.3

*Data through 1998.
Standard deviations of annual returns in parentheses.
Source: Ibbotson and Sinquefield [1976, 1982].

HISTORICAL EQUITY RETURNS AND SURVIVORSHIP BIAS

The real return on stocks, as I have emphasized [1998], has displayed a remarkable long-term stability. Over the entire 196-year period that I examine, the long-term after-inflation geometric annual rate of return on equity averages 7.0%. In the 1926-1998 period, the real return has been 7.4%, and since 1946 (when virtually all the thirteenfold increase in the consumer price index over the past two hundred years has taken place) the real return on equity has been 7.8%. The relative stability of long-term real equity returns is in marked contrast to the unstable real returns on fixed-income assets.

Some economists believe the 7% historical real

return on equities very likely overstates the true expected return on stocks. They claim that using the ex post equity returns in the United States to represent returns expected by shareholders is misleading. This is because no investor in the nineteenth or early twentieth century could know for certain that the United States would be the most successful capitalist country in history and experience the highest equity returns.

This "survivorship bias" hypothesis, as it has been called, is examined by Jorion and Goetzmann [1999] in "Global Stock Markets in the Twentieth Century." They conclude that of thirty-nine equity markets that existed in 1921, none of them show as high a real capital appreciation as the United States, and most of them have had substantial disruptions in their operations or have disappeared altogether. They report that the median real capital appreciation of non-U.S. markets has been only 0.8% per year as opposed to 4.3% in the U.S.[6]

But this evidence may be misleading. Total returns of a portfolio, especially over long periods of time, are a very non-linear function of the returns of the individual components. Mathematically it can be shown that if individual stock returns are lognormal, the performance of the *median* stock is almost always worse than the market portfolio performance.[7]

So, it is not surprising that the median performance of individual countries will not match the "world portfolio" or the returns in the dominant market. Jorion and Goetzmann recognize this near the end of their study when they show that compound annual real return on a GDP-weighted portfolio of equities in all countries falls only 28 basis points short of the U.S. return. In fact, because of the real depreciation of the dollar over this time, the compound annual *dollar* return on a GDP-weighted world is actually 30 basis points *higher* than the return on U.S. equities.[8]

But examining international stock returns alone does not give us a better measure of the equity premium. The equity premium measures the *difference* between the returns on stocks and safe bonds. Although stock returns may be lower in foreign countries than the U.S., the real returns on foreign bonds are substantially lower. Almost all disrupted markets experienced severe inflation, in some instances wiping out the value of fixed-income assets. (One could say that the equity premium in Germany covering any period including the 1922-1923 hyperinflation is over 100%, since the real value of fixed-income assets fell to zero while equities did not.)

Even investors who purchased bonds that promised precious metals or foreign currency experienced significant defaults. It is my belief that if one uses a world portfolio of stocks and bonds, the equity *premium* will turn out higher, not lower, than found in the U.S.[9]

TRANSACTION COSTS AND DIVERSIFICATION

I believe that 7.0% per year does approximate the long-term real return on equity indexes. But the return on equity *indexes* does not necessarily represent the *realized* return to the equityholder. There are two reasons for this: transaction costs and the lack of diversification.[10]

Mutual funds and, more recently, low-cost "index funds" were not available to investors of the nineteenth or early twentieth century. Prior to 1975, brokerage commissions on buying and selling individual stocks were fixed by the New York Stock Exchange, and were substantially higher than today. This made the accumulation and maintenance of a fully diversified portfolio of stocks quite costly.

The advent of mutual funds has substantially lowered the cost of maintaining a diversified portfolio. And the cost of investing in mutual funds has declined over the last several decades. Rea and Reid [1998] report a decline of 76 basis points (from 225 to 149) in the average annual fee for equity mutual funds from 1980 to 1997 (see also Bogle [1999, p. 69]). Index funds with a cost of less than 20 basis points per year are now available to small investors.

Furthermore, the risk experienced by investors unable to fully diversify their portfolios made the risk-return trade-off less desirable than that calculated from stock indexes. On a risk-adjusted basis, a less-than-fully diversified portfolio has a lower expected return than the total market.

Given transaction costs and inadequate diversification, I assume that equity investors experienced real returns more in the neighborhood of 5% to 6% over most of the nineteenth and twentieth century rather than the 7% calculated from indexes. Assuming a 3.5% real return on bonds, the historical equity premium may be more like 1.5 to 2.5 percentage points, rather than the 6.0 percentage points recorded by Mehra and Prescott.

PROJECTING FUTURE EQUITY RETURNS

Future stock returns should not be viewed independently of current fundamentals, since the price of

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stocks is the present discounted value of all expected future cash flows. Earnings are the source of these cash flows, and the average price-to-earnings (P-E) ratio in the U.S. from 1871 through 1998 is 14 (see Shiller [1989] for an excellent source for this series).

Using data from August 13, 1999, the S&P 500 stock index is 1327, and the mean 1999 estimate for operating earnings of the S&P 500 stock index of fifteen analysts polled by Bloomberg News is $48.47.[11] This yields a current P-E ratio on the market of 27.4. But due to the increased number of write-offs and other special charges taken by management over the last several years, operating earnings have exceeded total earnings by 10% to 15%.[12] On the basis of reported earnings, which is what most historical series report (including Shiller's), the P-E ratio of the market is currently about 32.[13]

There are two long-term consequences of the high level of stock prices relative to fundamentals. Either 1) future stock returns are going to be lower than historical averages, or 2) earnings (and hence other fundamentals such as dividends or book value) are going to rise at a more rapid rate in the future. A third possibility, that P-E ratios will rise continually without bound, is ruled out since this would cause an unstable bubble in stock prices that must burst.

If future dividends grow no faster than they have in the past, forward-looking real stock returns will be lower than the 7% historical average. As is well known from the dividend discount model, the rate of return on stocks can be calculated by adding the current dividend yield to the expected rate of growth of future dividends. The current dividend yield on the S&P 500 index is 1.2%. Since 1871, the growth of real per share dividends on the index has been 1.3%, but since 1946, due in part to a higher reinvestment rate, growth has risen to 2.1%. If we assume future growth of real per share dividends to be close to the most recent average of 2.1%, we obtain a 3.3% real return on equities, less than one-half the historical average.

A second method of calculating future real returns yields a similar figure. If the rate of return on capital equals the return investors require on stocks, the *earnings yield*, or the reciprocal of the price-earnings ratio, equals the forward-looking real long-term return on equity (see Phillips [1999] for a more formal development of this proposition). Long-term data support this contention; a 14 price-to-earnings ratio corresponds to a 7.1% earnings yield, which approximates the long-term real return on equities. The current P-E ratio on the S&P 500 stock index is between 27 to 32, depending on whether total or operating earnings are considered. This indicates a current earnings yield, and hence a future long-term and real return, of between 3.1% to 3.7% on equities.

One way to explain these projected lower future equity returns is that investors are bidding up the price of stocks to higher levels as the favorable historical data about the risks and returns in the equity market become incorporated into investor decisions.[14] Lower transaction costs further enable investors to assemble diversified portfolios of stocks to take advantage of these returns. The desirability of stocks may be further reinforced by the perception that the business cycle has become less severe over time and has reduced the inherent risk in equities.[15]

If these factors are the cause of the current bull market, then the revaluation of equity prices is a one-time adjustment. This means that future expected equity returns should be lower, not higher, than in the past. During this period of upward price adjustment, however, equity returns will be higher than average, increasing the historical measured returns in the equity market.

This divergence between increased historical returns and lower future returns could set the stage for some significant investor disappointment, as survey evidence suggests that many investors expect future returns to be higher, not lower, than in the past (see "PaineWebber Index of Investor Optimism" [1999]).

SOURCES OF FASTER EARNINGS GROWTH

Although the increased recognition of the risks and returns to equity may be part of the explanation for the bull market in stocks, there must be other reasons. This is because the forward-looking rates of return we derive for equities fall below the current 4.0% yield on inflation-protected government bonds. Although one could debate whether in the long run stocks or *nominal* bonds are riskier in real terms, there should be no doubt that the inflation-protected bonds are safer than equities and should have a lower expected return.

Hence, some part of the current bull market in stocks must be due to the expectations that future earnings (and dividend) growth will be significantly above the historical average. Optimists frequently cite higher growth of real output and enhanced productivity, enabled by the technological and communications revolution, as the source of this higher growth. Yet the long-run relation between the growth of real output and *per share* earn-

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ings growth is quite weak on both theoretical and empirical grounds. Per share earnings growth has been primarily determined by the reinvestment rate of the firm, or the earnings yield minus the dividend yield, not the rate of output growth.[16]

The reason why output growth does not factor into per share earnings growth is that new shares must be issued (or debt floated) to cover the expansion of productive technology needed to increase output. Over the long run, the returns to technological progress have gone to workers in the form of higher real wages, while the return per unit of capital has remained essentially unchanged. Real output growth could spur growth in per share earnings only if it were "capital-enhancing," in the growth terminology, which is contrary to the labor-augmenting and wage-enhancing technological change that has marked the historical data (see Diamond [1999] for a discussion of growth and real return).

But there are factors that may contribute to higher future earnings growth of U.S. corporations, at least temporarily. The United States has emerged as the leader in the fastest-growing segments of the world economy: technology, communications, pharmaceuticals, and, most recently, the Internet and Internet technology. Furthermore, the penetration of U.S. brand names such as Coca-Cola, Procter & Gamble, Disney, Nike, and others into the global economy can lead to temporarily higher profit growth for U.S. firms.

Nonetheless, the level of corporate earnings would have to double to bring the P-E ratio down to the long-term average, or to increase by 50% to bring the P-E ratio down to 20. A 20 price-to-earnings yield corresponds to a 5% earnings yield or a 5% real return, a return that I believe approximates realized historical equity returns after transaction costs are subtracted. For per share earnings to temporarily grow to a level 50% above the long-term trend is clearly possible in a world economy where the U.S. plays a dominant role, but it is by no means certain.

CONCLUSION

The degree of the equity premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than that estimated on earlier data. This is confirmed by the yields available on Treasury inflation-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.[17]

All of this makes it very surprising that Ivo Welch [1999] in a survey of over 200 academic economists finds that most estimate the equity premium at 5 to 6 percentage points over the next thirty years. Such a premium would require a 9% to 10% real return on stocks, given the current real yield on Treasury inflation-indexed securities. This means that real per share dividends would have to grow by nearly 8.0% to 9.0% per year, given the current 1.2% dividend yield, to prevent the P-E ratio from rising farther from its current record levels. This growth rate is more than six times the growth rate of real dividends since 1871 and more than triple their growth rate since the end of World War II.

Unless there is a substantial increase in the productivity of capital, dividend growth of this magnitude would mean an ever-increasing share of national income going to profits. This by itself might cause political ramifications that could be negative for shareholders.

ENDNOTES

This article is adapted from a paper delivered at the UCLA Conference, "The Equity Premium and Stock Market Valuations," and a Princeton Center for Economic Policy Studies Conference, "What's Up with the Stock Market?" both held in May 1999. The author thanks participants in these seminars and particularly Jay Ritter, Robert Shiller, and Peter L. Bernstein for their comments.

[1]A few economists believe these high levels of risk aversion are not unreasonable; see, e.g., Kandel and Stambaugh [1991].

[2]In the capital asset pricing model, equity risk premiums are derived from the *arithmetic* and not geometric returns. Compound annual geometric returns are almost universally used in characterizing long-term returns.

[3]Their wildly high 12.8% long-term inflation estimate in 1982 is derived by subtracting their low historical real yield from the high nominal bond rate. This overprediction has no effect on their estimated *real* returns.

[4]But real rates on *short-dated* bonds, for which unanticipated inflation should have been less important, were also extremely low between 1926 and 1980.

[5]I am very persuaded by the research of Campbell and Viceira [1998], who argue that in a multiperiod world the proper risk-free asset is an inflation-indexed annuity rather than the short-dated Treasury bill. This conclusion comes from intertemporal models where agents desire to hedge against unanticipated changes in the real rate of interest. The duration of such an indexed annuity is closely approximated by the ten-year inflation-indexed bonds.

[6]They are unable to construct dividend series for most foreign countries, but they make a not-unreasonable assumption that dividend yields in the U.S. were at least as high as abroad.

[7]Intuitively, the return of the winners more than compensates for the lower returns of the more numerous losers.

[8]Furthermore, the dollar return on the foreign portfolio is much better measured than the real return. These data are taken from Jorion and Goetzmann [1991], Tables VI and VII.

[9]To avoid the problems with default, gold is considered the "risk-free" alternative in many countries. But gold's long-term real returns are negative in the U.S. even before one considers storage and insurance costs. And precious metals are far from risk-free in real terms. The real return on gold since 1982 has been a negative 7% per year.

[10]I abstract from taxes, which reduce the return on both bonds and stocks.

[11]These data were taken from the Bloomberg terminal on August 16, 1999.

[12]From 1970 through 1989, operating earnings exceeded reported earnings by an average of 2.29%. Since 1990, the average has been 12.93%.

[13]There are other factors that distort reported earnings, some upward (underreporting option costs: see Murray, Smithers, and Emerson [1998]) and some downward (overexpensing R&D; see Nakamura [1999]). No clear bias is evident.

[14]This is particularly true on a long-term, after-inflation basis. See Siegel [1998, Chapter 2].

[15]Bernstein [1998] has emphasized the role of economic stability in stock valuation. Also see Zarnowitz [1999] and Romer [1999]. Other reasons given for the high price of equities rely on demographic factors, specifically the accumulations of "baby boomers." This should, however, reduce both stock and bond returns, yet we see real bond returns as high if not higher than historically.

[16]From 1871 to 1998, the growth of real per share earnings is only 1.7% per year, slightly less than obtained by subtracting the median dividend yield of 4.8% from the median earnings yield of 7.2%.

[17]This should not be construed as predicting that equity prices need fall significantly, or that the expected returns on equities are not higher, even at current levels, than those on fixed-income investments.

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Pollution Probe Interrogatory #17

Ref: Ex. C2-T1-S1, page 30

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Ms. McShane relies on survey findings of market professionals reported by Consensus Economics for her forecast(s) of the yields for 10-year Government of Canada bonds. At the bottom of this page, Ms. McShane states that "a reasonable expected value of the future equity market return is a range of 11.5-12.25%". How does this "reasonable expected value of the future equity market return" for Canada compare with near-term and longer-term forecasts for Canadian equity market returns that are drawn from publicly available surveys of market professionals?

Response

Based on the yearly published Watson Wyatt surveys of economists and portfolio managers, the median forecast return for the S&P/TSX composite for the long-term has been approximately 8.0 percent. The forecasts do not provide any supporting quantitative analysis nor do they indicate whether the results are in the nature of an arithmetic or geometric average, and thus do not provide a basis for estimating the cost of equity capital.

Pollution Probe Interrogatory #18

Ref: Ex. C2-T1-S1, page 32

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane explain how the standard deviation of a portfolio changes as the number of individual securities in the portfolio increases.

(b) How did Ms. McShane control for differences in the numbers of securities in each of the ten sectors?

Response

(a) The standard deviation decreases. That is why Ms. McShane used the average and median standard deviations of the separate sectors rather than the standard deviation of the market composite.

(b) Ms. McShane did not explicitly make adjustments for sample size. Such an adjustment would require not only recognizing the number of securities in the sector but also the market capitalization of each security in the sector, which can change materially (e.g., Nortel), making adjustments extremely difficult to quantify accurately. However, Ms. McShane tested the impact of different numbers of securities in each sector, by calculating the average variances and covariances of the individual securities in each sector (assuming that they were of equal size) for the five year period ending December 2006, and then "normalizing" each sector's standard deviation assuming an equal number (20) of securities. The ratio of the normalized standard deviation of returns of the utilities sector to the mean and median of the corresponding standard deviations for all 10 sectors was not materially different (it was, in fact, higher) from the unadjusted ratio for the same period.

Pollution Probe Interrogatory #19

Ref: Ex. C2-T1-S1, page 32

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane confirm that the underlying logic behind the adjusted beta method is that the beta is assumed to revert to a hypothesized true value of 1 over time.

(b) Please have Ms. McShane provide all evidence/materials of which she is aware that there is mean reversion in the betas of Canadian stocks.

(c) In the absence of any evidence that Canadian stock betas exhibit mean reversion to 1 and given that "utility returns have consistently been higher than what raw betas would indicate", does this not imply that utility returns have been too generous? Please explain.

Response

(a) It is confirmed. However, please see Ms. McShane's evidence at Ex. C2-T1-S1, page 35, specifically,

> "The deficiencies in 'raw' beta can be mitigated by using adjusted betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0. Use of adjusted betas implicitly recognizes that 'raw' utility betas do not adequately explain utility returns. For example, as illustrated above, 'raw' betas do not capture utilities' interest rate sensitivity. Further, the objective of the relative risk adjustment is to predict the investors' required return. Since utility returns have consistently been higher than what raw betas would indicate, adjusted betas are better predictors of utility returns than 'raw' betas." (footnotes excluded).

(b) To Ms. McShane's knowledge, there is no empirical evidence of mean reversion in the betas of Canadian stocks. However, please see response to (a).

(c) No. It means that "raw" betas are not a good predictor of the expected or required ROE.

Pollution Probe Interrogatory #20

Ref: Ex. C2-T1-S1, page 38

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

How do the utility equity returns reported in Table 3 compare with the comparable return estimates for the equity market over the 1956 - 2006 period?

Response

Please see Ex. C2-T1-S1, page 220 of 261, Schedule 4, page 3 of 3 of Ms. McShane's testimony.

Pollution Probe Interrogatory #21

Ref: Ex. C2-T1-S1, page 39

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

How was the optimism bias in analysts' forecasts, which is extensively documented in the scientific literature, removed?

Response

No adjustment was made to the analysts' growth forecasts. Please see Ms. McShane's testimony at Ex. C2-T1-S1, page 165, where Ms. McShane compared the forecast growth rates for the utility sample to the long-term expected growth in the economy over the entire period 1993 - 2007, and found that the average expected growth rate for the sample was lower than the long-term expected growth in the economy. She concluded that an expected growth rate for a sample of low risk utilities that is close to that of the economy as a whole would not be out of line with what investors would reasonably expect from mature utilities over the longer-term.

In regard to optimism or bias in the growth rates for low risk utilities, the BCUC, in its March 2006 decision (Order No. G-14-06) for Terasen Gas and Terasen Gas (Vancouver Island), concluded "The major criticism of the DCF method is that it relies on analysts' forecasts, which may be biased upwards. The Commission Panel does not find Dr. Booth's comments helpful in that his observations mostly cover U.S. technology analysts and the scandal on Wall Street concerning inappropriate analyst behaviour in an investment banking milieu. The Commission Panel finds that Dr. Booth's use of DCF estimates for U.S. Utilities covered by Standard & Poors, which included "multi-utilities" and energy marketing firms, should not be used as representative of U.S. utility returns. The Commission Panel is more persuaded by Ms. McShane's evidence which compares Value Line and I/B/E/S forecasts and finds no upward bias in the latter." Value Line is an independent research firm which neither buys nor sells securities. It thus has no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to investors.

Pollution Probe Interrogatory #22

Ref: Ex. C2-T1-S1, page 41

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please discuss the tenability of the estimated relationship given that the regression includes 30-year treasury yields or a highly correlated counterpart on both sides of the regression equation.

Response

The estimated relationship, which is between risk premiums and treasury yields, is equivalent to estimating the relationship between the bond yield and the cost of equity. In that case, the coefficient is 0.39, that is, the cost of equity increases (decreases) by 39 basis points for every one percentage point increase (decrease) in the long-term government bond yield. That relationship is the mirror of the regression on Ex. C2-T1-S1, page 41. There the equity risk premium increases (decreases) by 61 basis points for every one percentage point decrease (increase) in long Canada yields. There are a number of published studies that have estimated the relationship in the manner set out on Ex. C2-T1-S1, page 41, for example, Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", *Journal of Applied Finance*, 2001. The question presumes that, in the second relationship, there is a high correlation, when, in fact, the regression is intended to test whether or not a correlation, or the extent to which a correlation, exists.

Pollution Probe Interrogatory #23

Ref: Ex. C2-T1-S1, page 42

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

The returns from the sample of utilities supposedly reflect the ROE determinations of the various regulatory bodies. However, the Canadian ROE determinations include provisions of financial flexibility. This also applies to the two-stage DCF discussion on page 44. Please explain why risk premiums based on the returns for Canadian utilities do not already include a return component that reflects financial flexibility.

Response

Of the various market-based tests used to estimate the cost of attracting equity capital, (the CAPM, the DCF-based risk premium test, the historic risk premium test, the constant growth DCF model and the two-stage DCF model), only the historic risk premium test could potentially include any component for financial flexibility. The other tests, by their very construction, exclude any return related to financing flexibility; they are "bare-bones" costs of attracting equity capital. With respect to the historic risk premium test, it is not possible to isolate this potential return component from the total achieved market returns, as while allowed (and earned) returns are related to market returns, they are not equivalent. Market returns reflect investors' reactions to both allowed and earned returns. Given that the cost of attracting equity capital was estimated using all of the market-based tests listed above, the weight given to the historic risk premium test is relatively small, i.e., it accounts for less than 20% of the weight that was given to all the market-based tests. The typical Canadian adjustment to the bare-bones cost of attracting equity capital for financing flexibility has been 50 basis points. Thus, Ms. McShane's estimated cost of attracting equity capital would, at a maximum, already include a financing flexibility return component of less than 10 basis points of, i.e., 50 basis points X the less than 20% weight that was given to the historic risk premium test. As Ms. McShane's recommended adjustment for financing flexibility of 50 basis points is a minimum, the possibility that the "bare bones" cost of attracting equity capital might already contain a maximum of 10 basis points for financing flexibility is inconsequential.

Pollution Probe Interrogatory #24

Ref: Ex. C2-T1-S1, page 43

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

How does using a sample of proxies rather than the subject company mitigate circularity?

Response

It mitigates the circularity because the growth rate estimation is for companies other than the one the regulator is charged with setting the ROE for, and thus does not require speculating on the ROE that will be allowed in the specific utility's rate proceeding.

Pollution Probe Interrogatory #25

Ref: Ex. C2-T1-S1, page 45

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

What are the market-to-book ratios of the utility samples examined in Ms. McShane's evidence?

Response

The market/book ratios of the sample of low risk U.S. utilities were provided on Ex. C2-T1-S1, page 245 of 261, Schedule 21; the median is 2.0X. The market/book ratios of Canadian utilities were provided on Ex. C2-T1-S1, page 244 of 261, Schedule 20; the median was 1.8X. The median market/book ratios of the wires and high generation sample for the same period were 1.9X and 1.7 times respectively.

Pollution Probe Interrogatory #26

Ref: Ex. C2-T1-S1, page 49

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) What official definition of a business cycle was used by Ms. McShane to identify the 1994 - 2006 period as a complete business cycle in Canada?

(b) If the Canadian business cycle is being measured from peak to peak, what are the two peak years?

(c) If the Canadian business cycle is being measured from trough to trough, what are the two trough years in the 1994 - 2006 business cycle identified by Ms. McShane?

(d) Why are the years 1990 through 1993 not included in the Canadian business cycle examined in Ms. McShane's evidence?

(e) What year(s) is (are) recession year(s) in the 1994 - 2006 period in Canada?

Response

(a) - (e) The period 1994 - 2006 is not based on an official definition of a business cycle, which traditionally is measured from trough to trough. The most recent trough in the official business cycle in Canada ended in 1992, with 1993 continuing to reflect the hang-over of the effects of both the deep recession and the ongoing restructuring of the economy in part arising out of the provisions of NAFTA and thus relatively anemic growth (2.3 percent). The period 1994 - 2006 does not include a year of technical recession, since unlike the U.S., Canada did not experience a recession in 2001. The period does, however, include three years of slowdown, as demonstrated in the annual growth rates provided below, and a balance of years of expansion (above trend growth), economic downturns and growth at approximately trend (average) levels.

YEAR	GROWTH RATE	YEAR	GROWTH RATE
1994	4.8%	2000	5.2%
1995	2.8%	2001	1.8%
1996	1.6%	2002	2.9%
1997	4.2%	2003	1.9%
1998	4.1%	2004	3.1%
1999	5.5%	2005	3.1%
		2006	2.8%

Pollution Probe Interrogatory #27

Ref: Ex. C2-T1-S1, page 50

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane explain why a similarity in the market/book ratios of the proxy samples relative to the market composites indicates no evidence of market power.

(b) Please have Ms. McShane confirm that none of the firms in the market composites have market power.

Response

(a) The existence of market power and thus the ability to earn above average returns would be reflected in an above average valuation, i.e., materially above that of the market composite. There is no basis for concluding that on average the firms that make up the Canadian or U.S. equity market composites exhibit market power and their market/book ratios have, on average, been well above book value. If the market/book ratios of the low risk industrials were materially higher than the market composite's, one could infer that the low risk industrial sample could exert market power and earn higher than normal economic profits. As they are not, there is no evidence that the sample exhibits market power.

(b) Ms. McShane cannot confirm that no individual company in the sample has market power. The conclusion with respect to market power was drawn on the basis of the sample as a whole.

Pollution Probe Interrogatory #28

Ref: Ex. C2-T1-S1, page 124

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane explain how the discussion in Appendix B relates to the residual income model of stock valuation.

Response

The residual income model for stock valuation is a discounted cash flow model that estimates the value of a stock using the discounted value of the economic profit of the firm after applying a charge for the cost of capital (debt plus equity). The comparable earnings test results include total earnings, including economic profits in excess of the cost of capital, that low risk (comparable) unregulated companies are able to earn, but not on a discounted basis.

Pollution Probe Interrogatory #29

Ref: Ex. C2-T1-S1, page 129

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane confirm that she did not mean to define beta as the "covariability of the security with the market (M)".

Response

More precisely the beta represents the covariance of the returns of a stock and those of the market, divided by the variance in the market returns. The calculations of beta throughout the testimony reflect this definition.

Pollution Probe Interrogatory #30

Ref: Ex. C2-T1-S1, page 131

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane discuss how her CAPM discussion relates to the Black version of the CAPM.

(b) Please have Ms. McShane discuss how her CAPM discussion relates to conditional (time-varying) multiperiod versions of the CAPM.

Response

(a) The Black version of the CAPM (zero beta) recognized that the traditional risk-free asset (which, in academic studies is typically a short-term government security), was not, in reality, risk-free and replaced it with a portfolio of assets whose returns did not co-vary at all with the market. The Black version of the CAPM suggested that the return on the zero beta asset (a hypothetical construct) would be higher than the traditional risk-free rate, and the capital market line would be less steep than the capital market line of the simple CAPM. The Black model, as it relies on a hypothetical construct for the zero-beta asset, is a theoretical, rather than practical model.

(b) The simple CAPM model used to estimate the cost of equity is a static model. Conditional models of the CAPM essentially hypothesize that betas and risk premiums are time varying. The empirical work that has been done using conditional models suggests that a conditional model may explain more of the cross-section of market returns. However, Ms. McShane is not aware of any practical applications of a conditional CAPM, and has never seen such a model proposed for, or used to, estimate the cost of equity for a regulated company.

Pollution Probe Interrogatory #31

Ref: Ex. C2-T1-S1, page 132

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane quantify the portion of the income trust return that was a return of capital and not a return on capital.

Response

Ms. McShane has not attempted to isolate the return of capital from the return on capital. However, the portion of the 16.4 percent total return, referenced at Ex. C2-T1-S1, page 136, that was due to an increase in the price index alone was approximately 5.3 percent. Ms. McShane is not aware of any studies or analyses that have quantified the portion of the return of the index that is due to return of capital versus return on capital. She notes that the BG Advantaged S&P/TSX Income Trust Index Fund, which replicates to the extent possible the return of the S&P/TSX Income Trust Index, indicates that it expects a significant portion of the distribution of the fund to be return of capital for income tax purposes

Pollution Probe Interrogatory #32

Ref: Ex. C2-T1-S1, page 138

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane explain how realized stock returns decrease with an increased investor demand for stocks.

Response

They do not. The reference is intended to say that returns to Canadian investors have been negatively impacted by the foreign content restriction.

Pollution Probe Interrogatory #33

Ref: Ex. C2-T1-S1, page 148

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane identify all of the studies that she refers to the following in her testimony: "several studies of historic and equity risk premiums". If these studies are not readily accessible to others, please also provide copies of the studies.

Response

Please see response to Interrogatory L-12-16.

Pollution Probe Interrogatory #34

Ref: Ex. C2-T1-S1, pages 154 - 156

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane provide references to the peer-reviewed literature that provides support for the methodology that she uses to test the relationship between beta and return in the Canadian equity market.

Response

Ms. McShane's analysis was not constructed based on a peer-reviewed methodology. It is a simple correlation between betas and returns which demonstrates that over a long period of time, the betas of lower and higher risk sectors of the economy and the returns they have achieved have not conformed to the relationship predicted by the CAPM, leading to the conclusion that depending on a raw beta to predict the expected return is problematic at best.

Pollution Probe Interrogatory #35

Ref: Ex. C2-T1-S1, page 161

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane provide her reasoning behind the following statement: "As a pragmatic matter, the application of a constant growth model is compatible with the likelihood that investors do not forecast beyond five years."

Response

The reasoning was that, beyond five years, there is too much uncertainty regarding economic conditions or the specific circumstances of an individual company to allow any degree of accuracy in forecasting.

Pollution Probe Interrogatory #36

Ref: Ex. C2-T1-S1, page 164

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane discuss all the studies published since 1990 that support her conclusion that "investment analysts' growth forecasts serve as a better surrogate for investor expectations than historic growth rates".

(b) Please have Ms. McShane discuss all the studies published since 1990 that do not support her conclusion that "investment analysts' growth forecasts serve as a better surrogate for investor expectations than historic growth rates".

Response

(a) Ms. McShane has not done a literature survey. However, little research has been done on the properties of the long-term forecasts, as noted in Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", *Journal of Applied Finance*, Vol. 11, 2001. The authors, who use analysts' forecasts to develop an estimate of the risk premium for the market, go on to say,

> "Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia."

Since the forecasts continue to be widely disseminated and reported, and stock prices continue to react positively and negatively to differences between forecast and actual growth rates, investors clearly give significant weight to the forecasts when forming their own expectations.

The criticism associated with using analysts' forecasts is optimism bias. Optimism bias is least likely to impact relatively stable industries and companies like utilities where the business model and potential outcomes in terms of earnings are well understood. A relatively recent study entitled "The Level and Persistence of Growth Rates", *Journal of Finance*, Vol. LVIII, No. 2, 2003 by Chan, Louis C., Karceski, Jason and Lakonishok, Josef, which divided all U.S. stocks with available I/B/E/S growth rates into value-weighted portfolios found that the companies with the highest expected growth rates had

actual growth rates in excess of the levels forecast five years previously, but the lowest growth portfolio (where utilities would fall) did not exhibit the same tendency.

In addition, as noted in response to L-12-21, the average analysts' earnings growth forecast for the benchmark U.S. utilities for the period covered by the DCF-based equity risk premium analysis is measurably lower than the average forecast for long-term growth in the economy over the same period. Ms. McShane notes that the DCF model continues to be the primary model relied upon by U.S. regulators, who presumably are aware of, and have considered, the evidence as it specifically regards utilities and continue to find the DCF evidence based on analysts' forecasts compelling.

(b) See response to (a) above.

Pollution Probe Interrogatory #37

Ref: Ex. C2-T1-S1, page 165

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

A number of studies argue that the growth of publicly traded firms is less than the growth in GDP. Assuming that this is the case, please have Ms. McShane explain why the growth rates of higher dividend-paying firms (such as the utilities) are expected to be higher than those of lower dividend-paying firms.

Response

They are not. The average expected long-term growth rate in earnings for the S&P 500 companies (which have an average dividend yield of approximately two percent), for example, as per the most recent I/B/E/S forecasts, is 12.5 percent. The corresponding long-term forecast growth rates for the sample of benchmark utilities as per the I/B/E/S forecasts were 4.9 percent on an average basis and 4.5 percent on a median basis, with a corresponding dividend yield of approximately 4.5 percent.

Pollution Probe Interrogatory #38

Ref: Ex. C2-T1-S1, page 166

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please have Ms. McShane clarify if "I/B/E/S consensus of analysts' earnings forecasts for the first five years" refers to a single consensus forecast for the first five years or one consensus forecast for each of the first five years.

Response

It refers to a single consensus forecast for the next five years, compiled at approximately the same time as the prevailing prices used to calculate each firm's dividend yield.

Pollution Probe Interrogatory #39

Ref: Ex. C2-T1-S1, page 168 and169

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane identify which screens (such as removing companies that paid no dividends in any year 2001-2006) were applied at the beginning of her estimation period.

(b) Please have Ms. McShane provide the list of Canadian firms used in effecting the comparable earnings test in her filed evidence for Northwest Territories Power Corporation (NTPC) in November 2006 (i.e. one year earlier). Please also have Ms. McShane discuss each change in firm membership between the Canadian sample used in her pre-filed evidence in this proceeding for the comparable earnings test and the Canadian sample used in her filed evidence in the most recent NTPC proceeding for the same test.

Response

(a) The only criterion that was applied at the beginning of the estimation period (that is, it covers the full 1994 - 2006 period) is the "no missing book equity" or "negative equity" criterion.

(b) The attached table provides the requested comparison.

All Companies Used in NWTPC 11/06	Reason Not in OPG 11/07
ALGOMA CENTRAL CORP	Trading Volume was below 125,000 shares in 2006
ANDRES WINES LTD/ANDREW PELLER LTD	
ARBOR MEM SVCS INC -CL B	
ASTRAL MEDIA INC -CL A	
CANADA BREAD CO LTD	
CANADIAN TIRE CORP -CL A	
EMPIRE CO LTD -CL A	Common Equity for 2006 was not available at time of selection
FINNING INTERNATIONAL INC	
LEON'S FURNITURE LTD	
LINAMAR CORP	
LOBLAW COMPANIES LTD	
MAGNA INTERNATIONAL -CL A	
MAPLE LEAF FOODS INC	
REITMANS (CANADA) -CL A	
THOMSON CORP	
TORSTAR CORP -CL B	
TRANSCONTINENTAL INC -CL A	
UNI-SELECT INC	
VAN HOUTTE INC	Common Equity for 2006 was not available at time of selection
WESTON (GEORGE) LTD	

Companies Used in OPG 11/07 Not in NWTPC 11/06	Reason Not in NWTPC 11/06
JEAN COUTU GROUP	DBRS Rating was B
METRO INC -CL A	1994-2004 returns were more than 1 standard deviation above the average
TVA GROUP INC -CL B	No rating was available from CBS, DBRS, or S&P

Pollution Probe Interrogatory #40

Ref: Ex. C2-T1-S1, page 168 and 169

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Please provide peer-reviewed references to support each of the following:

(a) The comparable earnings method has a theoretical basis.

(b) The comparable earnings method can be empirically tested.

(c) The comparable earnings method has been subject to peer review and publication.

(d) The potential rate of error of the comparable earnings method can be determined.

(e) The scientific community is in general agreement on the standards controlling the application of the comparable earnings method.

(f) The theory or method of implementation of the comparable earnings method has been generally accepted by the scientific community.

(g) The comparable earnings method has not been created solely for the purposes of rate of return determination for regulated entities.

Response

(a) - (g) The comparable earnings test is specifically applicable to utilities that are regulated on an original cost book value basis, for the specific purpose of adherence to the fairness standard. The limited purpose of the test is in stark contrast to the CAPM or DCF tests, which are more generally applicable across industries, used to estimate the required or expected rate of return on market values. Thus, it would be unlikely that the comparable earnings test has been subject to the types of peer review suggested in the question. Nevertheless, the importance of adherence to the fairness standard in setting the ROE (return on equity) and capital structure for regulated utilities regulated on the basis of original cost warrants giving weight to the comparable earnings test to properly take account of the unique construct.

Pollution Probe Interrogatory #41

Ref: Ex. C2-T1-S1, pages 194 and 195

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

In the estimation of generation-only betas, Ms McShane states: "I have used assets as a proxy for the relative contribution of each division (or business segment) to the company as a whole".

(a) What empirical evidence exists to support this assumption? If this evidence is not readily accessible to others, please also provide copies of this evidence.

(b) Please have Ms. McShane discuss whether or not the use of this proxy makes any implicit assumption about the relative return-on-assets and risks of each division.

Response

(a) The choice of assets was not based on empirical evidence. Ideally, the proxy would be some measure of income. However, since the purpose of the analysis was to isolate generation risk from wires risk, and there are no separate data available for the income for the "wires" and "generation" portions of the utility businesses, Ms. McShane was required to utilize a measure of contribution for which there were consistent data available. Since utilities are capital intensive (hard asset-based) industries, using assets is a reasonable choice of allocation factor for this purpose. The analysis that was conducted by Board Staff's expert witnesses (Drs. Lazar and Prisman) in EB-2006-051 for Hydro One to distinguish between the risks of distribution and transmission similarly used assets as an allocator.

(b) It implicitly makes the assumption that the proportion of the income contributed by each division is directly related to the proportion of the assets in each area of business. This is a reasonable assumption for integrated utilities whose "wires" and "generation" operations are treated as a single business with a single cost of capital that reflects their composite risks. Ms. McShane has taken account of the risks of each area of business through the use of differential betas.

Pollution Probe Interrogatory #42

Ref: Ex. C2-T1-S1, page 221

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

(a) Please have Ms. McShane discuss the probability of a negative return over the next year for the regulated portion of a typical utility in the Utilities sector index included in this schedule.

(b) Please have Ms. McShane characterize the probability of a negative return over the next year for a typical non-regulated firm in each of the other 9 sector indices included in this schedule as being lower, the same, or higher than her response to part (a) of this interrogatory.

(c) Please have Ms. McShane explain her response to part (b) of this interrogatory.

Response

(a) Ms. McShane does not have the data to specifically estimate the probability of a negative return for the regulated portion of the company only. Over the 1956 to 2006 period, the return for the Utilities Index (Gas/Electric from 1956 - 1987 and Utilities Index from 1988 - 2006) has been negative seven years out of 51. Assuming that the next year's return is random, the probability, based on history is approximately 14 percent.

(b) Ms. McShane does not have the data readily available to assess individual companies. Over the longest period for which there are consistent data available for sectors of the TSE Index, 1956 - 2003, on average, there was a negative return for each sector 33 percent of the time. Assuming that the next year's return is random, the probability, based on history is approximately 33 percent.

(c) Please see response to (b).

Pollution Probe Interrogatory #43

Ref: Ex. C1-T1-S2, page 5

Issue Number: 2.4
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

(a) Please explain the inconsistency between OPG's use of the long-term interest-rate forecast for 10-year Government of Canada bonds by Global Insight and Ms. McShane's use of the forecast for the same financial instrument from Consensus Economics.

(b) Please have OPG provide a detailed account of the costs of OPG's hedging activities that are embedded in its effective debt cost forecasts.

Response

(a) OPG has subscribed to Global Insight for a number of years, using this publication as an input into its planning process. Global Insight is a recognized company that provides monthly and quarterly updates on key economic indicators that OPG tracks for forecasting. OPG also receives economic information from its bank group as another third party source. Continued use of these information sources for the test period enhances the consistency and comparability to prior years. OPG does not subscribe to Consensus Economics.

(b) The costs of OPG's hedging activities for the Niagara Tunnel Project (NTP) and Non Project Related debt are shown in Ex. C1-T2-S2 Tables 6 and 7 respectively. As of December 31, 2007, hedging for the NTP has resulted in cash payments totaling $4,297,127 to counter party banks to settle the interest rate swaps on their maturity dates based on the change in market rates from the date the transactions were entered into until settlement. Similarly the hedging activities for the non project related debt has resulted in OPG receiving cash payments totaling $247,650 as of December 31, 2007. The effective cost of debt reflects the actual cost or benefit of each hedge transaction amortized consistent with the term of the underlying bond issue on a straight-line basis, applied as an interest rate adjustment to the underlying interest rate cost on amount of debt actually issued. The interest rate adjustment was calculated based on the term of the debt (10 years) and actual existing amount of the debt drawn versus the hedged amount.

For interest rate hedges that mature in 2008 and 2009 the financial impact on OPG will not be known until maturity. However, the mark-to-market value of these hedges is shown in Ex. C1-T2-S2, Tables 8 and 9 as at December 31, 2007. The impact of these hedges on the forecast effective cost of debt is based on the weighting of the hedged

and the unhedged debt amounts for each issue which is separately determined for each issue in Ex. C1-T2-S2, Table 4b, note 10 for 2008 and Ex. C1-T2-S2, Table 5b, note 6 for 2009.

Pollution Probe Interrogatory #44

Ref: Ex. C2-T1-S1, page 53

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide copies of the debt rating reports from Standard & Poor's and DBRS referenced in footnotes 54-56: Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007; Standard & Poor's, *Credit FAQ: Implied Government Support as a Rating Factor for Hydro One Inc. and Ontario Power Generation Inc.*, October 20, 2005.

Response

Attached, please find:

1. Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007

2. Standard & Poor's, Credit FAQ: Implied Government Support as a Rating Factor for Hydro One Inc. and Ontario Power Generation Inc., October 20, 2005

Filed: 2008-04-08
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Attachment 1

STANDARD &POOR'S

RATINGSDIRECT

Summary:

Ontario Power Generation Inc.

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Summary:

Ontario Power Generation Inc.

Credit Rating: BBB+/Positive/--

Rationale

The ratings on Ontario Power Generation Inc. (OPG), a large electricity generator, reflect the close relationship between the company and its higher rated owner, the Province of Ontario (AA/Stable/A-1+). A fixed price for output derived from OPG's baseload nuclear and hydroelectric assets, a diverse portfolio of more than 22,000 MW of in-service generating capacity, and a strong cost-competitive position in the Ontario wholesale electricity market, support OPG's cash flows and provide further credit strength. Operational and technology risk associated with nuclear assets, revenue constraints, volume risk related to production from OPG's unregulated assets, and a satisfactory financial profile partially offset the company's credit strengths.

The government's demonstrated willingness to financially assist the publicly owned generator is reflected in a two-notch rating enhancement to the stand-alone long-term corporate credit rating on OPG. This view is supported by the company's strategic position in both the electricity sector and overall economy of Ontario. The government's continued direction of the company's investments in major new generation and provision of debt financing for the business is further evidence of a close relationship. Standard & Poor's Ratings Services believes that OPG is unlikely to be privatized in the foreseeable future. The bulk of OPG's C$3.2 billion debt outstanding as of Dec. 31, 2006, is held in the form of notes payable by the company's government shareholder.

Cash flow from nuclear, and a portion of hydroelectric, production is supported by legislated prices of C$49.50 per megawatt-hour (MWh) and C$33.00 per MWh, respectively, until April 30, 2008. Based on forecast production, operating costs, and existing capital structure, the company should be able to earn about a 5% ROE from these assets that generate more than half of its energy revenues. We expect the Ontario Energy Board to assume full regulatory oversight of these assets in 2008. OPG can request future recovery of significant unexpected capital and operating costs associated with its regulated assets.

The fuel diversity and large number of units in OPG's generation portfolio mitigate the risk of operational disruptions and enhance the company's business position. The portfolio includes baseload nuclear (6,606 MW), predominantly run-of-the-river hydroelectric (6,946 MW), intermediate coal-fired (6,438 MW), and peaking gas- and oil-fired (2,140 MW) generation assets. Furthermore, OPG's hydroelectric assets are on multiple river systems, the diversity of which serves to partially offset OPG's exposure to hydrology risk.

OPG has a strong cost-competitive position in its primary market, the Ontario wholesale electricity market. OPG is the dominant player in the Ontario electricity market, producing at least two-thirds of the approximately 150 terawatt-hours (TWh) of electricity sold in Ontario each year. The combined output of the generator's baseload regulated assets (about 60 TWh per year) is among the lowest cost generation in the province; as such, dispatch risk is not material. The bulk of the remaining electricity demand in Ontario comes from competitive-based offers from OPG and other generators in an hourly spot market administered by the Independent Electricity System Operator.

Nuclear generating assets have significant operational and technology risks. OPG operates 10 of its 12 CANDU

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nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in the past. OPG's nuclear liability risk-sharing agreement with the province caps the company's used nuclear fuel liabilities and is a positive for the credit. Furthermore, OPG will have access to segregated funds to manage the costs associated with used fuel and eventual nuclear decommissioning. The decommissioning fund was fully funded as of Dec. 31, 2006, based on the 1999 Ontario Nuclear Funds Agreement reference plan.

OPG's nonregulated cash flow is constrained by a government-imposed revenue cap until April 30, 2008, and is also exposed to volume risk. The revenue cap affects approximately 85% of production from OPG's unregulated coal-fired and hydroelectric assets; the cap will rise to C$48/MWh in 2008-2009 from C$47/MWh in 2007-2008. Volume risk relates to fluctuations in Ontario-based market demand, the inherent uncertainty of available water flows, and competitively priced imports from neighboring markets. Cash flow from the remaining 15% of nonregulated production faces volatile commodity prices but can benefit from higher market prices.

OPG's has an intermediate financial profile, with adjusted funds from operations (AFFO) interest coverage of 3.7x and AFFO-to-total debt of 10.6% in 2006, compared with 4.9x and 14%, respectively, in 2005. Lower cash flow in 2006 was due to weather-related lower demand in Ontario. Although subject to modest volatility due to some limited market price exposure, we expect OPG's financial profile to remain relatively stable in 2007, absent any material change to its financial policies and capital structure. In assessing OPG's key credit ratios, such as funds from operations (FFO) interest coverage and FFO-to-average total debt, cash payments to segregated nuclear liability funds are treated as an operating expense.

Liquidity

Based on available credit lines, cash on hand, expected cash flow, and credit facilities established with its shareholder to fund government directives, OPG's liquidity should be sufficient to meet cash outlay commitments in the next 12 months.

OPG has a C$1 billion, fully committed credit facility with a C$500 million, 364-day term tranche maturing May 22, 2007, and a C$500 million, three-year revolving tranche maturing May 22, 2009. The C$1 billion facility serves as a backstop to the generator's C$1 billion CP program. At Dec. 31, 2006, there was C$15 million of commercial paper outstanding; the bank line remained undrawn. As such, the bulk of the facility remained available to support collateral requirements that arise from the company's exposure to commodity market-related risk. OPG also had about C$55 million available under its separate C$240 million standby LOC facilities. LOCs issued relate primarily to the company's pension obligations. OPG also has credit facilities in place with its shareholder to fully debt finance new developments under construction.

AFFO of C$600 million or more in 2007 is sufficient to fund sustaining capital expenditures of about C$470 million. Growth capital commitments of about C$350 million are expected to be debt financed. We expect total capital expenditures of about C$820 million in 2007, compared with C$637 million in 2006. There is the potential for OPG's shareholder to expect continued dividend payments. Based on the dividend payout in 2006 of 35% of 2005 earnings, dividend payout in 2007 could be as much as C$170 million based on earnings in 2006.

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Outlook

The positive outlook reflects an improved pricing framework and regulatory environment. The rating will likely move a notch higher if OPG can manage its expenses and operational performance within the bounds of its current license agreement and maintain its satisfactory financial profile in 2007 with a similar outlook for 2008 and beyond. For the rating to move a notch higher, there will also have to be an expectation of continued relative stability in both Ontario's electricity policy and regulatory framework and a clear financial policy for the company. The outlook could be revised to stable or negative as a result of a sustained period of significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities, or higher operating expense due to poor hydrology and higher prices for coal, with no related increase to the revenue cap. As the shareholder relationship evolves in the long term, there could be a change to the degree of support factored into the rating.

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STANDARD &POOR'S RATINGSDIRECT

RESEARCH

Credit FAQ: Implied Government Support As A Rating Factor For Hydro One Inc. And Ontario Power Generation Inc.

Publication date: 20-Oct-2005
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The rating action by Standard & Poor's Ratings Services on electricity generator Ontario Power Generation Inc. (OPG; BBB+/Positive/--) on Sept. 27, 2005, incorporates the application of its government support methodology and highlights circumstances where the level of implied government support can differ between related entities.

This credit FAQ will help users of the ratings understand Standard & Poor's approach to rating government-related issuers by providing an explanation of the criteria and how and what level of implied government support is factored into ratings. Furthermore, an explanation of the level of support factored into the rating on OPG and why it differs from that assigned to its sister company, the electricity transmission and distribution utility, Hydro One Inc. (A/Stable/A-1), is provided. The article also looks at circumstances where the support might change over time.

Hydro One and OPG are both wholly owned by the Province of Ontario (AA/Stable/A-1+). The Ontario Energy Board (OEB) independently regulates Hydro One, while the provincial government sets the current prices received for the bulk of OPG's generation output, and has established legislation whereby the bulk of OPG's assets will move to independent regulation over time.

Frequently Asked Questions

When and how does Standard & Poor's factor government support into a rating?
Essentially the issue of rating support for government-owned entities falls into three broad categories. The categories, ratings treatment, basis for classification, and some examples in the Canadian market of the classification are outlined in table 1. In none of these cases is direct or percentage ownership the determining factor to the degree of expected support.

Table 1

Broad Categories of Government-Supported Entities

Category	Ratings Treatment	Basis of Classification	Examples
1	Appropriate to equalize the rating on the entity with the rating on the government.	Where a business unit or entity is viewed as highly aligned and integral to the government's policy directives and finances.	The corporate credit rating on Chatham Kent Energy Inc. is equalized with that of its owner, the Municipality of Chatham-Kent. Other examples include the equalizing of the ratings on the debt issued by Hydro Quebec and Newfoundland and Labrador Hydro with that of their provincial owners based on explicit and unconditional guarantees, although other obligations of the utilities are not explicitly guaranteed.
2	In these instances the corporate credit rating on the entity is notched off the rating on the government from one to six notches.	Entities that have a defined public policy role in which the government defines their performance and prospects. Support is both a matter of policy and law with support expressed through statutory or ultimate –	The ratings on the University Health Network, York University, and the York Region District School Board are notched off the rating on the Province of Ontario.

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		rather than timely – guarantees.	
3	Rather than a notching down from the rating on the government, the rating is notched up from the stand-alone rating on the company and could be notched up one, two, or three notches.	Where the relationship is supportive and often enhances the entity's underlying credit strengths through helpful policies and the possibility of direct assistance.	Globally this category includes the majority of rated and unrated government-supported entities and it is within this category that Hydro One and OPG sit.

Whether the corporate or debt ratings on a government-owned entity reflect explicit or implied support from its owner, and the extent to which the ratings might benefit, depends on the application of Standard & Poor's rating methodology as it applies to government-owned entities. For detailed information on the criteria, please refer to "Revised Rating Methodology For Government-Supported Entities" published June 5, 2001, on RatingsDirect, Standard & Poor's Web-based credit research and analysis system, at www.ratingsdirect.com.

Why do Hydro One and OPG fall into Category 3?
Some of the reasons why Hydro One and OPG do not fall into the first and second categories but into the third category include the following. There is no formal guarantee of Hydro One and OPG obligations by the province; they are not government departments, ministries, or agencies; and the two companies play a relatively minor part in the province's finances. As such, Category 1 is not appropriate. The lack of explicit statements of support through policy and law, lack of a defined public policy role for both businesses, and a desire by the government that both businesses act as stand-alone commercial operations, means Category 2 is not appropriate either. It could be argued that OPG falls into Category 2, given its current role as a means of government influence on the mix of generation in Ontario (that is, the phasing-out of coal-fired generation) and on the price of power paid by households, but under current government policy OPG is expected to increase its financial independence from the government, and the government is expected to distance itself from the oversight of the company as it transitions to regulatory oversight by the OEB. Moreover, there is an expectation OPG will continue to be part of a market-based electricity sector in Ontario. The third category, in which Hydro One and OPG sit, is appropriate given the ability of both companies to operate independently of government, while the government retains the ability to reduce business risks for the two companies, to varying degrees, and provide direct assistance if required.

What is the basis of Standard & Poor's approach to government-owned entities?
Standard & Poor's assigns ratings taking a long-term view of credit, and while it appears remote the government of Ontario will not remain the 100%-owner and supporter of Hydro One and OPG for the foreseeable future, circumstances can and do change. It is with the potential for changing circumstances in mind that the ratings on Hydro One and OPG are more closely aligned to the underlying creditworthiness of the individual companies rather than their owner. Governments change, government policies change, views on ownership change, economic circumstances change, and the financial ability and willingness of the province to support its enterprises can change also.

Fundamentally, it is not possible to predict the future political willingness to support a separately incorporated entity. Politics by definition is populist, expedient, and capricious, and creditors should not dismiss the likelihood of change.

Hydro One and OPG are not viewed as being so integrated with government to warrant equalization of the ratings or for the ratings to be notched off from that on the province. Furthermore, the two businesses can operate independently from government and are expected to act commercially and be financially sustainable, although OPG will continue to source the bulk of its debt funding from the provincial government for some time yet. The recent OPG board independent decision not to proceed with further refurbishments of its Pickering nuclear plant is evidence of a move to a more autonomous OPG. The government does not offer, and is reluctant to offer, implicit government guarantees or financial support for the obligations of Hydro One or OPG. Furthermore, to equate the ratings on Hydro One and OPG with that of the rating on the province or to assign a rating close to that assigned to the province introduces a credit cliff in the event of a material change in circumstances. It must be remembered that it was not so long ago that these two entities were both the subject of proposed initial public offerings. From Standard & Poor's perspective, to notch up from the stand-alone rating provides greater transparency and stability to the ratings for existing and potential holders of Hydro One and OPG's long-term bonds.

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What level of government support is factored into the ratings on Hydro One and OPG?
The long-term rating on Hydro One benefits from one notch of implied government support, while the long-term corporate credit rating on OPG benefits from two notches.

Both entities are strategic within the economy, and the government has demonstrated willingness to financially assist both businesses. OPG has no long-term public debt, with the government continuing to hold notes payable of C$3.9 billion from OPG as of June 30, 2005.

What explains the difference in the level of implied support assigned to Hydro One and OPG?
The difference in implied support between the two provincial owned entities comes down to the degree of control and influence the government has over each company's financial well-being. Although the government of the day can ultimately bring forth legislation for whatever changes it feels appropriate for the long-term structure of Hydro One, OPG, and the Ontario regulatory framework and market structure, the ability of the government to readily influence and control the two companies' financial position in the short term is not the same.

The potential ease and timeliness by which the government can take action to support OPG relative to Hydro One contribute to the difference in the level of notching. There are three primary support mechanisms that highlight the greater likelihood and ease with which the government is able to support OPG's creditworthiness, namely the provision of financing, the degree of corporate oversight, and the transitional regulatory framework. The provincial government is currently the key debt provider for OPG but not for Hydro One. Hydro One's C$5.5 billion in debt funding as of June 30, 2005, was raised through the public capital market. The rigor with which the government oversees Hydro One does not appear to be as intrusive as it is with OPG. Furthermore, the provincial government is the direct current price-setter for OPG's generation output--both regulated and unregulated, while there are established processes by an arm's-length regulator for setting Hydro One's distribution and transmission tariffs.

The government's current position as the determiner of OPG's regulated and nonregulated generation prices and key financier means that the instruments or mechanisms at its control to help (or hinder) OPG operationally and financially are more readily available than with Hydro One. As a consequence, the government has a big influence on OPG's financial performance through its ability to determine what returns the company will earn, what debt it will assume, and in some cases what new major capital expenditure will be undertaken. Despite the government influence in setting prices for OPG's regulated generation, recent legislation permits the company to apply to the provincial regulator, the OEB, to seek variance accounts for extraordinary costs, and to apply for a change to the current government-imposed prices. Of issue for this course of action are the unproven process and timing involved. Furthermore, regardless of potential change in prices by the OEB, the government retains its price-setting autonomy for OPG's nonregulated generation. As such, the shareholder has more levers at its disposal to influence the company financially in a timely fashion relative to those by which it can influence Hydro One. Hydro One is largely beholden to the independent provincial regulator in terms of its operational performance and returns, and in addition to oversight by its shareholder, Hydro One is subject to the scrutiny and disclosure requirements of the debt capital markets. Furthermore, any material financial support provided to Hydro One in times of financial stress beyond an initial and immediate suspension or deferral of dividends, would most likely involve direct cash equity injections or short-term financing and in doing so, would introduce administrative and political elements into decision making that increase the risk of inadequate or less timely support.

Will the level of implied support incorporated into the ratings remain consistent over time?

The simple answer is no. It might, but a number of elements dictate whether the implied government support and the level of support is appropriate, and as such, a change in circumstances can lead to a change in the level of support and the rating assigned. A more obvious example would be a change in ownership. Assuming a new owner has a neutral impact on Hydro One or OPG's creditworthiness, the ratings on these two businesses would likely gravitate to the stand-alone ratings. Conversely, a new owner might also have a positive or negative influence on the issuer ratings if fully consolidated with that of the new owner. It can be expected that in the event of a foreshadowed sale or IPO, the ratings would be adjusted to reflect the changing circumstances in advance of the execution of the sale.

Less obvious developments could also change the level of implied support, particularly that assigned to OPG. The basis on which the level of government support for OPG is differentiated from Hydro One could

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change over time and lead to the level of implied support assigned to OPG moving to be more in line with the one notch incorporated into the Hydro One rating, barring any change in ownership. In the next few years, OPG is expected to move to a situation where it will operate in a manner and environment more in line with that in which Hydro One now finds itself. The company will likely be largely regulated by an independent regulator, may issue debt in its own right, and may not be subject to the same level of government oversight and directives that it currently is. Under these circumstances, the provincial government is unlikely to exert the same influence and control over OPG's operational and financial direction and it would be appropriate to revisit the level of support at that time. Of comfort to future bondholders, however, is that if such an environment transpires as expected, OPG's underlying creditworthiness would likely also improve such that the potential scaling-back of the level of implied support would be unlikely to alter the corporate credit rating on OPG. The expectation of changing circumstances and a change in the relationship are also the main reasons the level of support factored into the rating on OPG is not to the full extent of the three notches that the criteria allows for entities which fall into Category 3.

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Pollution Probe Interrogatory #45

Ref: Ex. C2-T1-S1, page 59

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane states on page 59:

"Nevertheless, dispatch risk for the regulated assets is currently relatively low. That risk will rise as additional low marginal cost generation (which can bid below cost but receive a price specified in its PPA with the OPA) becomes available or demand drops."

Does Ms. McShane expect that dispatch risk will remain low during the test period? Please explain.

Response

Yes; the reference in the testimony (Ex. C2-T1-S1, page 59) to currently low dispatch risk for the regulated assets encompasses the test period, which only extends through the end of 2009.

Pollution Probe Interrogatory #46

Ref: Ex. C2-T1-S1, page 69

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane states on page 69:

"The Board Report raises a risk that regulated revenues will be indirectly impacted by the market price, as it raises the spectre of caps on regulated payments if they exceed the market price for an extended period of time."

Does Ms. McShane expect that such caps will become a reality during the test period? Please explain.

Response

Ms. McShane has no information other than what was indicated in the Board Report. Note, however, that Ms. McShane states, "The risk assessment proceeds on the assumption that the Board will not impose a cap on regulated payments tied to market prices."

Pollution Probe Interrogatory #47

Ref: Ex. C2-T1-S1, page 73

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane states on page 73:

"Given the significant volatility in uranium prices, which is not predictable and beyond management control, OPG is requesting a variance account to record variances between forecast and actual uranium costs. The proposed variance account would cover the preponderance of OPG's fuel price risk."

Please identify and explain any fuel price risk that would remain in the presence of the requested variance account.

Response

Not all uranium price increases or decreases would flow through to the variance account in the year the price impact happens. As a result, the impact of changes in uranium input prices in one period may not be accounted for until a subsequent period. When fuel costs are higher than anticipated, OPG would have to pay the higher costs, but recovery of those higher costs would be deferred.

Pollution Probe Interrogatory #48

Ref: Ex. C2-T1-S1, page 75

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane states on page 75:

"While Regulation 53/05 mitigates the risks to OPG as it requires that the OEB ensure that OPG recovers its costs related to ONFA, increased cash requirements for funding or a reduction in the time period over which those costs must be recovered could result in material pressures on the regulated payments."

Please explain how "increased cash requirements for funding or a reduction in the time period over which those costs must be recovered" could arise. Would these not be subject to regulatory mitigation should they arise? If not, please explain why not.

Response

Since cash funding requirements are not part of the revenue requirement (recovery is based on accrual accounting, not cash accounting), the referenced sentence should read, "While Regulation 53/05 mitigates the risks to OPG as it requires that the OEB ensure that OPG recovers its costs related to ONFA, increased cash requirements for funding **could pressure OPG's cash flows** or a reduction in the time period over which those costs must be recovered could result in material pressures on the regulated payments."

Since the revenue requirement is based on accrual accounting, but cash funding of the liabilities requires approval of the Province under ONFA, there can be a lag between the recovery of the expense through regulated payments and the requirement for funding of the liabilities. In other words, cash contributions may have to be made before recovery of the expense in rates. The estimate of liabilities is based on an approved reference plan prepared through the Ontario Nuclear Funds Agreement in place between the Province and OPG.

The current reference plan was approved by the Province in December 2006. The liabilities are estimated using a number of planning assumptions and related cost estimates. The estimated costs can change primarily due to: (1) changes in waste management and decommissioning program cost estimates; (2) changes in station life;

(3) changes in economic indices; and (4) changes in in-service assumptions for long term waste management facilities.

With respect to the period over which the costs must be recovered, it is dependent on the estimated remaining useful life of the individual stations. A reduction in the remaining useful life would reduce the period over which the expense would be recovered. While the Board could mitigate the potential pressure on regulated payments by altering the recovery period, the longer the recovery period is extended, the higher the risk that there will be no viable means of recovering the unfunded liability through regulated payments, e.g., there is a change in the regulatory framework.

Pollution Probe Interrogatory #49

Ref: Ex. C2-T1-S1, pages 60 and 63

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Discussing regulatory risks, Ms. McShane states on page 60:

"For purposes of the business risk assessment, I proceed on the assumption that OPG will be treated no differently from any other utility subject to the Board's jurisdiction: OPG will be provided a reasonable opportunity to recover its prudently incurred costs and earn a return that reasonably reflects the risks to which it is exposed."

On page 63, she then states: "On balance I view the regulatory risk for OPG as higher than that of the typical regulated utility in Canada and in Ontario."

Please explain how these two statements are consistent.

Response

The first statement simply means that the Board would seek to apply the same standards and principles to OPG as to other utilities under its jurisdiction. The second statement needs to be read in conjunction with the paragraph that follows:

> "As the Board suggested in its November 20, 2006 report, the application of cost of service regulation to generation is a relatively unique phenomenon, with no track record upon which to gauge the outcome. The uncertainty of the "end state" is amplified by the fact that OPG will be regulated in a market environment which is a hybrid of regulation and competition, which creates additional pressure on regulated rates in a period of potentially significant cost increases (e.g., decommissioning costs, other post-retirement benefit expenses)."

Pollution Probe Interrogatory #50

Ref: Ex. C2-T1-S1, page 64

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide copies of all reports from debt rating agencies supporting the following statements by Ms. McShane on page 64:

"Political intervention in the industry restructuring process to shield customers from the impact of rising market prices for power was the principal reason given by the debt rating agencies for their downgrades to the debt ratings in 2003 of Ontario electric utilities. The debt rating agencies view the risk of further political intervention in the Ontario market as having declined since those debt rating reductions occurred in 2003. Nevertheless, the risk of future political intervention in the market is higher than in other Canadian jurisdictions, as there continue to be unresolved issues in an evolving Ontario electricity marketplace."

Response

The following debt report attachments support the conclusion that political intervention was the principal reason for the downgrades:

1. DBRS Enersource Downgrade Jan 2003
2. DBRS Hydro Ottawa Downgrade Jan 2003
3. DBRS Toronto Hydro Downgrade Jan 2003
4. S&P Hamilton Downgrade May 2003
5. S&P Hydro One Downgrade Feb 2003
6. S&P Hydro Ottawa Downgrade Jun 2003
7. S&P Toronto Hydro Downgrade Apr 2003

The following attachments support the conclusion that the debt rating agencies view the risk of further political intervention as having declined, but references to the potential have continued to be referenced (e.g., the November 2007 DBRS report for OPG).

8. DBRS Enersource Report Jun 2007
9. DBRS Hydro Ottawa Report Sep 2007
10. DBRS OPG Nov 2007
11. DBRS Toronto Hydro Ratings Report Jul 2007

12. S&P Hamilton Analysis Apr 2007
13. S&P Hydro One research update March 2008
14. S&P Hydro One Summary Nov 2007
15. S&P Hydro Ottawa Summary Dec 2006
16. S&P Toronto Hydro Analysis Nov 2007

Ms. McShane has found no references to political risk in any debt rating reports that have been issued since the beginning of 2006 for any other utilities in Canada which have been relied upon in her testimony.

Filed: 2008-04-08
EB-2007-0905
L-12-50
Attachment 1

Insight beyond the rating.

Mar 28, 2008

Enersource Corporation

Downgrades to A (low), Removed from UR-Negative

Date Of Release: Jan 31, 2003 15:35

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

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DBRS is downgrading the corporate rating on Enersource Corporation ("Enersource" or the "Company") to A (low) from "A." The trend is Stable. The rating is removed from "Under Review with Negative Implications", where it was placed on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Enersource and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity. As such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Enersource had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

In December 2002, Mississauga city council had voted in support of Enersource remaining as a commercial entity as set out in the resolution that gave the shareholders the option to declared whether the Company would (1) remain as a commercial entity, as it has been since first incorporating in 1999; or (2) revert back to being a not-for-profit entity. Becoming a not-for-profit entity would have warranted a further downgrade, as its financial profile would have become significantly weaker.

Enersource's rating continues to be supported by the following factors: (1) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; (2) a favourable franchise area with a well-diversified customer base, and a moderate load growth rate which should contribute to stable earnings growth over the medium to long term; and (3) shareholders, the City of Mississauga and Borealis, that are financially sound and able to provide additional equity injections or limit dividend requirements, if necessary, to further support the Company's capital structure. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Enersource's rating report will follow the release of the Company's 2002 financial statements.

Issuer	Debt Rated	Rating Action	Rating	Trend	Notes	Latest Event
Enersource Corporation	Issuer Rating	Downgraded	A (low)	Stb	last rpt. 05/22/02	Jan 31, 2003

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Enersource Corporation

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Attachment 2

Insight beyond the rating.

Mar 28, 2008

Hydro Ottawa Holding Inc.

Downgrades to A (low), Rating Remains Under Review with Negative Implications

Date Of Release: Jan 31, 2003 15:34

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

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DBRS is downgrading the corporate rating on Hydro Ottawa Holdings Inc ("Hydro Ottawa" or the "Company") to A (low) from "A." The trend is Stable. The rating remains "Under Review with Negative Implications," where it was placed under on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Hydro Ottawa and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity. As such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Hydro Ottawa had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

The rating will remain "Under Review with Negative Implications" until Ottawa municipal council votes on the resolution to declare whether Hydro Ottawa will: (1) remain as a commercial entity, as it has been since first incorporating in 2000; or (2) revert back to being a not-for-profit entity. Should Hydro Ottawa revert back to being a not-for-profit entity, a further downgrade would be warranted, as the Company's financial profile would become significantly weaker. Remaining as a commercial entity would warrant the removal of "Under Review with Negative Implications" status.

The Ottawa City Council is expected to vote on the resolution in February 2003. If Council does not make a decision on the resolution by March 9, 2003, Hydro Ottawa will automatically revert back to being a not-for-profit entity, as defined in Bill 210.

Hydro Ottawa's rating continues to be supported by the following factors: (1) a favourable franchise area; (2) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; and (3) a strong supportive parent, the City of Ottawa, that is able to provide additional equity injections or limit dividend requirements, if necessary, to further support Hydro Ottawa's capital structures. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Hydro Ottawa's rating report will follow the release of the Company's 2002 financial statements and the outcome of the municipal council's vote on the resolution.

Issuer	Debt Rated	Rating Action	Rating	Trend	Notes	Latest Event
Hydro Ottawa Holding Inc.	Corporate Rating	Downgraded	A (low)	Stb	last rpt. 04/16/02	Jan 31, 2003
Hydro Ottawa Holding Inc.	Corporate Rating	Under Review - Negative	A (low)	Stb	UR-neg. 01/31/03	Jan 31, 2003

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Hydro Ottawa Holding Inc.

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Filed: 2008-04-08
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Attachment 3

Insight beyond the rating.

Mar 28, 2008

Toronto Hydro Corporation

Downgrades to A (low), Conf. at R-1 (low), Ratings Remain UR with Negative Implications

Date Of Release: Jan 31, 2003 15:42

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

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DBRS is downgrading the corporate rating on Toronto Hydro Corporation ("Toronto Hydro" or the "Company") to A (low) from "A" and confirming the commercial paper rating at R-1 (low), both with a Stable trend. Both ratings remain "Under Review with Negative Implications," where they were placed on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Toronto Hydro and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity, as such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Toronto Hydro had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

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Attachment 3

The one-notch downgrade reflects these risks.

The ratings will remain “Under Review with Negative Implications” until the Toronto municipal council votes on the resolution to declare whether Toronto Hydro will: (1) remain as a commercial entity, as it has been since first incorporating in 1999; or (2) revert back to being a not-for-profit entity. Should Toronto Hydro revert back to being a not-for-profit entity (earning a zero return on equity), a further downgrade would be warranted, as the Company’s financial profile would become significantly weaker. Remaining as a commercial entity would warrant the removal of “Under Review with Negative Implications” status.

The Toronto City Council is expected to vote on the resolution by February 5, 2003. If Council does not make a decision on the resolution by March 9, 2003, Toronto Hydro will automatically revert back to being a not-for-profit entity, as defined in Bill 210.

Toronto Hydro’s rating continues to be supported by the following factors: (1) a favourable franchise area; (2) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; and (3) a strong supportive parent, the City of Toronto. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Toronto Hydro’s rating report will follow the release of the Company’s 2002 financial statements.

Issuer	Debt Rated	Rating Action	Rating	Trend	Notes	Latest Event
Toronto Hydro Corporation	Commercial Paper/Short-Term Obligations	Confirmed	R-1 (low)	Stb	last rpt. 02/21/02	Jan 31, 2003
Toronto Hydro Corporation	Commercial Paper/Short-Term Obligations	Under Review - Negative	R-1 (low)	Stb	UR-neg. 01/31/03	Jan 31, 2003
Toronto Hydro Corporation	Senior Unsecured Debentures & MTNs	Downgraded	A (low)	Stb	last rpt. 02/21/02	Jan 31, 2003
Toronto Hydro Corporation	Senior Unsecured Debentures & MTNs	Under Review - Negative	A (low)	Stb	UR-neg. 01/31/03	Jan 31, 2003

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Toronto Hydro Corporation

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Attachment 4

STANDARD &POOR'S

RATINGSDIRECT

Hamilton Utilities Off Watch, Ratings Lowered on Regulatory, Political Risk; Outlook Stable

Credit Analyst:
Jenny Catalfo, Toronto (1) 416-507-2557; Damian DiPerna, Toronto (1) 416-507-2561

TORONTO (Standard & Poor's) May 16, 2003--Standard & Poor's Rating Services today said it lowered its long-term corporate credit rating on electricity distribution company Hamilton Utilities Corp. to 'A' from 'A+'. At the same time, the senior unsecured debt rating was lowered to 'A' from 'A+'. The ratings were removed from CreditWatch, where they were placed Nov. 13, 2002. The outlook is stable.

"The ratings actions reflect a material increase in business risk following significant government intervention in the regulatory process in Ontario, which began with the mandated three-year phase-in of the 2001 ROE revenue requirement and continued with a four-year freeze on distribution service rates, as well as commodity prices," said Standard & Poor's credit analyst Jenny Catalfo. The four-year distribution service rate freeze disallows the third and final phase-in of the 2001 ROE revenue requirement, effectively constraining cash flows over the period.

The ratings on Hamilton Utilities, a municipally owned utility holding company, reflect its moderately low-risk business profile and strong financial position. The company's low-risk business profile is supported by regulated electricity distribution assets, which are expected to account for 85% of projected consolidated assets, and supportive regulation that allows for the flow-through of all power costs to customers, while nonregulated operations are managed with a conservative business strategy. Although Hamilton Utilities' service franchise includes a sizable industrial customer segment, a fixed-rate structure should

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minimize earnings volatility associated with the economic cycle. The company's cash flows should be relatively stable in the longer term.

Nevertheless, government intervention in the regulatory process in the past few years has been material, increasing the company's exposure to political and regulatory risk. The established precedent for government intervention has contributed to a lack of transparency, as well as made the regulatory process more onerous, as utility companies must now obtain ministerial approval before they can submit filings to the Ontario Energy Board (OEB).

Hamilton Utilities has taken extraordinary steps to strengthen its balance sheet to mitigate the adverse impact of the four-year government-imposed rate freeze on cash flows. As a result, key financial ratios should remain easily within ranges anticipated last year. With a projected debt-to-capital ratio of about 45%, funds from operations-to-interest coverage should be better than 4.0x. Hamilton Utilities is expected to maintain the strongest financial profile in the Standard & Poor's Canadian utility universe.

The stable outlook reflects the strength of Hamilton Utilities' financial position, which Standard & Poor's believes is robust enough to allow the company to cope with the financial pressures related to the four-year rate freeze. The ratings incorporate a modest level of regulatory uncertainty; however, a material adverse change in government direction or further political intervention in the regulatory process would involve a reassessment of the current ratings.

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Fixed Income in the left navigation bar, select Credit Ratings Actions.

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STANDARD
&POOR'S

RATINGSDIRECT®

February 21, 2003

Hydro One Inc. Ratings Lowered on Heightened Regulatory Risk, Off Watch; Outlook Negative

Credit Analyst:
Jenny Catalfo, Toronto (1) 416-507-2557; Damian DiPerna, Toronto (1) 416-507-2561

TORONTO (Standard & Poor's) Feb. 21, 2003--Standard & Poor's Ratings Services today said it lowered its long-term corporate credit rating on electricity transmission and distribution company Hydro One Inc. to 'A-' from 'A'. At the same time, the ratings on the company were removed from CreditWatch, where they were placed Nov. 13, 2002. The outlook is now negative.

"The ratings actions reflect a material increase in business risk following significant government intervention in the regulatory process, as well as concerns related to the financial challenges facing Ontario electricity distribution companies as a result of the government mandated four-year rate freeze on transmission and distribution service rates," said Standard & Poor's credit analyst Jenny Catalfo.

Standard & Poor's will hold a teleconference to discuss the ratings actions Mon., Feb. 24, 2003, at 3:00 p.m. ET. (See "Teleconference Information" below for details.)

In addition, the senior unsecured debt rating on Toronto, Ont.-based Hydro One was lowered to 'A-' from 'A', the short-term corporate credit and global scale commercial paper ratings were lowered to 'A-2' from 'A-1', and the Canadian national scale commercial paper rating was lowered to 'A-1(Low)' from 'A-1(Mid)'.

The ratings on Hydro One reflect the company's moderately low-risk

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business profile and average financial position. The company's business profile reflects its regulated electricity transmission and distribution assets, which generate virtually all of Hydro One's operating cash flows and contribute to relative cash flow stability in the longer term. Nevertheless, government intervention, and the risk of continued intrusion in the regulatory process, has materially increased the company's overall business risk exposure. As a result, the regulatory process has become significantly less transparent and has been made more onerous as utilities are now required to secure the Minister's approval before they can even submit filings to the Ontario Energy Board. Regulated utilities' operating risk remains low as they are still permitted to fully pass through to customers all power costs.

The ratings on Hydro One incorporate limited benefits attributed to the province's ongoing ownership, in the absence of formal credit support from the province, and given the potential that Hydro One could eventually still be privatized.

Hydro One's financial position is expected to steadily and materially improve in the next three years as a result of the recouponing (a reduction in interest rates) on about C$2 billion of government-held debt securities and cost containment measures that will mitigate to a large degree the adverse impact of the four-year rate freeze on distribution and transmission rates. Although Hydro One's financial flexibility is constrained by the lack of access to equity capital markets and substantial debt maturities in the next five years, operating cash flows are expected to be sufficient to fund capital expenditures and C$1 billion in existing lines of credit should be adequate to address annual debt maturities. Furthermore, like many other Canadian regulated utilities, the company's financial position is constrained by a thin 36% allowed common equity base.

The negative outlook likely will remain in place for at least one to two years and could be revised to stable as and when transparency and stability are restored to the regulatory environment, and/or Hydro One's success in mitigating the financial challenges associated with the rate freeze materializes.

Teleconference Information

Standard & Poor's will hold a teleconference Mon., Feb. 24, 2003, at 3:00 p.m. ET, to discuss the ratings actions on Hydro One Inc. The dial-in information is as follows:

Live-dial-in number: (Canada/U.S.) 1-212-287-1859
Confirmation number: 2610138
Passcode: CANADA
Duration: 45 minutes approximately (including Q&A)
Participants: Jenny Catalfo, Damian Di Perna, Nicole Martin
Replay number: (Canada/U.S.) 1-402-220-3037 (The replay will expire on Tues., March. 10, 2003.)

The call will begin promptly at the time indicated. Please call at least 10 minutes before the scheduled start of the call to complete the precall

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registration process. There is no charge to participate other than long-distance telephone charges, if applicable. Participants will be asked to provide their name, title, company affiliation, and fax number. Replays will be available two hours after the call is completed on Standard & Poor's Web site at www.standardandpoors.com under Events, Teleconferences. For more information contact Lucy Williams in Toronto at 416-507-2533.

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Fixed Income in the left navigation bar, select Credit Ratings Actions.

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STANDARD
&POOR'S

RATINGSDIRECT®

June 19, 2003

Hydro Ottawa Holdings Inc. Ratings Lowered to 'BBB+', Off Watch; Outlook Negative

Credit Analyst:
Bhavini Patel, CFA, Toronto (1) 416-507-2558; Damian DiPerna, Toronto (1) 416-507-2561

TORONTO (Standard & Poor's) June 19, 2003—Standard & Poor's Rating Services today said it lowered its long-term corporate credit rating on Ontario-based, electricity distribution company Hydro Ottawa Holdings Inc. to 'BBB+' from 'A'. At the same time, the rating was removed from CreditWatch where it was placed Nov. 13, 2002. The outlook is negative.

"Hydro Ottawa is facing a material increase in business risk following significant government intervention in the regulatory process in Ontario," said Standard & Poor's credit analyst Bhavini Patel. Government intervention began with the mandated three-year phase-in of the 2001 ROE revenue requirement and continued with a four-year rate freeze on distribution service rates, as well as nonrecovery of transition costs, additions to rate base, or increases in cost of service until 2006.

The rating on Hydro Ottawa, a municipally owned utility holding company, reflects a moderate business profile. The company's business profile is supported by efficient distribution assets, which account for 86% of projected 2005 assets and 75% of 2005 projected funds from operation (FFO). Hydro Ottawa has a diversified customer base with a material government services sector that should contribute to cash flow stability. The company's consolidated business profile, however, is characterized by a significant and comparatively larger projected investment in non-regulated businesses, including a fiber network and an energy operation, which exposes the company to market price risk (currently 16 MW of hydroelectric-based generating capacity). Hydro Ottawa's financial

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profile is weak for the ratings category. Regulatory directives maintain at least 40% equity at the regulated operations, which constrains the company's financial profile. Profitability and cash flow ratios will be materially controlled in the next four years due to the rate freeze and, therefore, no longer reflect an 'A' rating. FFO interest coverage ratios are expected to range from 2.8x-4.2x and FFO to average total debt is projected to be 13%-20% in the next three years.

Increasing involvement in non-regulated businesses, as well as a lack of regulatory stability and transparency, contributed to an increased business risk score, which would require a stronger financial profile to maintain the rating at previous levels. Event risk is also a material industry-wide concern, as the provincial government's plan to reintroduce a two-year transfer tax holiday that might stimulate a much-needed rationalization of the electricity distribution industry. Current ratings in the industry do not incorporate this risk and such transactions will be assessed as, and when, they occur.

The negative outlook could be revised to stable if regulatory stability and transparency are restored and Hydro Ottawa's financials improve. The negative outlook does not imply that Standard & Poor's expects credit quality to deteriorate; rather, it suggests that Standard & Poor's requires the business and financial positions to stabilize to support the current rating.

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Credit Ratings Actions.

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STANDARD &POOR'S

RATINGSDIRECT®

April 25, 2003

Toronto Hydro Off Watch, Ratings Lowered on Regulatory Risk, Four-Year Rate Freeze

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TORONTO (Standard & Poor's) April 25, 2003--Standard & Poor's Ratings Services today said it removed its ratings on Toronto Hydro Corp. from CreditWatch, where they were placed Nov. 13, 2002. At the same time, the long-term corporate credit and senior unsecured debt ratings on the company were lowered to 'A-' from 'A'. The outlook is negative.

"The ratings actions reflect a material increase in regulatory risk following significant government intervention in the regulatory process in the past few years, as well as concerns related to the financial challenges facing Ontario electricity distribution companies as a result of the November 2002 government mandated four-year rate freeze on distribution service rates," said Standard & Poor's credit analyst Jenny Catalfo.

The ratings on Toronto Hydro are supported by the company's moderately low-risk business profile and average financial position. The company's business profile reflects regulated electricity distribution assets, which are expected to generate about 85% of future operating cash flows, and will contribute to relative cash flow stability in the longer term. Nevertheless, government intervention and the risk of continued intrusion in the regulatory process have materially increased the company's exposure to regulatory risk. As a result, the regulatory process has become significantly less transparent and has been made more onerous as utilities are now required to secure the Minister's approval before they can even

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submit filings to the Ontario Energy Board. Regulated utilities' operating risk remains low as they are still permitted to fully pass through to customers all power costs, and local distribution companies (LDCs) will not be held accountable for reliability and productivity measures under a performance-based regulatory model.

Toronto Hydro's financial position is expected to be weaker than originally expected because of the rate freeze. The company continues to focus on cost containment measures which should partially mitigate the adverse impact of the rate freeze. Like all other Ontario LDCs, however, Toronto Hydro is facing some material increases in annual pension expenses. Without a recovery of this expense sooner than 2006, Toronto Hydro, like a number of other LDCs, could find it difficult to contain costs sufficiently to prevent a further deterioration in its financial position in the near term.

Although Toronto Hydro's financial flexibility is constrained by the lack of access to equity capital markets, operating cash flows are expected to be sufficient to fund capital expenditures, and the company has no need for additional financing to address existing operations. Like many other Canadian regulated utilities, the company's financial position is constrained by a thin 35% allowed common equity base.

The negative outlook likely will remain in place for at least one to two years and could be revised to stable as and when transparency and stability are restored to the regulatory environment, or Toronto Hydro's success in mitigating the financial challenges associated with the rate freeze materializes.

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Fixed Income in the left navigation bar, select Credit Ratings Actions.

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Insight beyond the rating.

Enersource Corporation

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RATING

Rating	Trend	Rating Action	Debt Rated
A	Stable	Confirmed	Issuer Rating

RATING HISTORY	Current	2006	2005	2004	2003	2002
Issuer Rating	A	A	A	A (low)	A (low)	A

RATING UPDATE

DBRS has confirmed the rating of Enersource Corporation (Enersource or the Company) at "A" with a Stable trend. Enersource continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its solid financial profile, and a strong franchise area with a favourable customer mix.

The confirmation is also supported by the improving regulatory outlook in Ontario. Since the last imposition of rate caps in Ontario in December 2002, there has not been any major political interference.

The Company's financial metrics have steadily improved and continue to benefit from the growth in EBIT and earnings, which have trended upwards since F2004 primarily due to distribution rate increases and a rise in electricity consumption, partially offset by higher operating costs. The Company has produced free cash flow surpluses since F2002, but will likely incur a very modest and manageable free cash flow deficit in the near-term due to an expected increase in capital expenditure.

The Ontario Energy Board's (OEB) recent decision on the Cost of Capital and 2nd Generation Incentive Regulation for electricity distributors in Ontario is expected to be largely credit neutral for Enersource in the medium term as the regulation does not affect Enersource's cash flow in any significant manner through April 2010. (Continued on page 2.)

RATING CONSIDERATIONS

Strengths

- Low business risk owing to Enersource's predominantly regulated electricity distribution operations
- Solid balance sheet and reasonable credit metrics
- Strong franchise area and favourable customer mix

Challenges

- Political risk and regulatory uncertainty
- Low regulatory returns
- Earnings are sensitive to the volume of electricity sold
- Refinancing risk

FINANCIAL INFORMATION

	For the year ended December 31				
	2006	2005	2004	2003	2002
EBIT interest coverage (times)	2.04	2.13	1.86	1.69	1.72
Total debt-to-capital	58.0%	59.0%	59.6%	59.1%	60.4%
Cash flow/total debt (times)	17.6%	17.5%	15.5%	13.7%	13.1%
Cash flow/capital expenditures (times)	1.42	1.67	1.63	1.21	1.02
Reported Net income ($ millions)	17.2	13.4	11.7	7.6	10.8
Cash flow from operations ($ millions)	50.9	50.6	44.8	39.7	38.6
Return on average equity	8.4%	6.7%	5.9%	3.9%	5.7%
Electricity throughputs (millions kWh)	7,833	7,996	7,690	7,594	7,583

THE COMPANY

Enersource Corporation is a holding company that owns Enersource Hydro Mississauga (EHM), a regulated electricity distribution company, and Enersource Services Inc., a non-regulated holding company. Enersource Services Inc. consists of two wholly owned subsidiaries: (1) Enersource Telecom, a dormant company that formerly operated a fibre-optic data networks and telecommunications company and (2) Enersource Hydro Mississauga Services, which provides engineering, design, construction and operations services, streetlight construction and maintenance services for the City of Mississauga. Enersource Corporation is 90% owned by the City of Mississauga, and 10% owned by BPC Energy Corporation, a subsidiary of Ontario Municipal Employees Retirement System.

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RATING UPDATE (Continued from Page 1.)

Over the next three years, the OEB will be re-basing the rates with full-cost-of-service proceedings for all distributors in Ontario, and Enersource has been selected to be in the first group to go through the re-basing of rates for the 2008 rate year, with the 3rd Generation Incentive Rate Mechanism applied in succeeding years, up to the 2010 rate year. The regulatory framework beyond 2010 remains uncertain, but DBRS expects the OEB will maintain a reasonable regulatory framework that should likely include cost of service recovery, a market-based rate of return and a performance-based incentive mechanism.

EBIT is expected to increase moderately in F2007, primarily due to the OEB's two separate decisions in 2006. Cash flows for F2008 and beyond will depend largely on the 2008 re-basing of rates and the 3rd Generation Incentive Rate Mechanism, but is generally expected to be sufficient to fully fund capital expenditures (estimated to be $50 million, including the $9 million allocated for Smart Meter installations) and dividends over the medium term.

Political intervention still remains a risk, especially in light of rising electricity commodity prices and anticipated increases in transmission and distribution rates over the medium to longer term. Should the total cost of electricity to consumers rise too quickly, the government could interfere with the OEB's rate-making process or cap rates, as has happened in the past. However, DBRS notes the current government has made a strong commitment to passing on the full cost of electricity to consumers.

RATING CONSIDERATIONS

Strengths

(1) Almost 100% of Enersource's earnings and cash flows are generated from its low-risk, regulated distribution subsidiary, EHM. The Company's already limited exposure to non-regulated businesses was further reduced due to the divesture of its non-regulated electric water-heater rental and certain specific telecom assets. Management has indicated that exposure to higher-risk, non-regulated businesses will continue to remain limited.

(2) The Company's balance sheet remains solid with leverage at 58%, EBIT interest coverage ratio at just over two times and cash flow-to-debt at almost 18%. These ratios are acceptable for the current rating category given the low business risk for the Company stemming from its regulated electricity distribution operations.

(3) Enersource's franchise area, the City of Mississauga, is the sixth-largest municipality in Canada. It has a population of approximately 700,000 with favourable annual population growth of approximately 2.5% over the past five years. Population growth is expected to continue to be solid over the medium term, providing a basis for continued stable earnings growth. Approximately 55% of Enersource's revenues are derived from commercial customers. Further, EHM's exposure to more-cyclical industrial customers is limited to less than 15% of total revenues. The Company's favourable customer mix, coupled with a strong, growth-oriented service area has provided Enersource with a relatively stable and predictable demand load year-over-year.

Challenges

(1) Political risk and regulatory uncertainty is a significant challenge for local distribution companies (LDCs) in Ontario. The most significant risk in the near term is the possibility of political intervention, such as the imposition of rate caps with the passing of Bill 210 in December 2002, should the cost of electricity to end-consumers rise too quickly. Higher prices will arise from (a) costs associated with new generation capacity being added within the province; (b) higher distribution costs following a re-basing during the 2008-2010 period; and (c) the recovery of approximately $4 billion in transmission upgrades in the province during the next ten years. Should prices increase too quickly, especially around election time, there is a risk that the government would intervene in the rate-setting process. DBRS considers this risk to be reasonably low. Furthermore, there is regulatory uncertainty arising from the OEB's decision on December 20, 2006 concerning the Cost of Capital, and the 2nd Generation Incentive Regulation, which is effective only until 2010. The OEB has not indicated what the regulatory framework will resemble after 2010.

(2) The approved ROE of 9.0% for 2007 is low and has been in decline in recent years primarily due to the low-interest rate environment. Lower ROEs have a negative impact on earnings, but the impact has been largely offset by a larger rate base and stable amount of debt.

(3) Earnings and cash flow for electricity-distribution companies are partially dependent on the volume of electricity sold and, hence, revenue earned from electricity sales. Seasonality, economic cyclicality and year-over-year changes in weather patterns directly impact the volume of

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electricity sold and revenue earned from electricity sales. In addition, economic growth impacts customer and load growth. However, Enersource's favourable customer mix and growing customer base helps mitigate these risks.
(4) Enersource's long-term debt currently consists entirely of a $290 million private placement with Borealis Infrastructure Trust, which matures in May 2011. Even though this bullet maturity poses a refinancing risk to Enersource, DBRS notes that the Company's credit profile, coupled with stable cash flows generated from strong franchise area with growing customer base, largely moderate this risk.

REGULATION

Regulatory Update

- Enersource's electricity distribution operations are regulated by the OEB under the Electricity Act, 1998 (the Electricity Act).
- Currently, EHM operates on a cost-of-service/rate-of-return basis. For 2007, ROE is set at 9.0% with a deemed capital structure of 60%/40%.
- On April 12, 2006, OEB released a decision that allowed a growth of $23.4 million or 5.2% in EHM's rate base. Furthermore, on October 3, 2006, OEB revised its April 12, 2006 decision and allowed for the full recovery of additional expenses of approximately $1.1 million annually, as well as the disposition of retail settlement-variance liabilities of approximately $2.7 million over a two-year period.
- On December 20, 2006, OEB released its final decision on the Cost of Capital and the 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. The decision included the following:
  - No major changes for the 2007 rate-setting period (May 2007 to April 2008), except for the implementation of the performance-based regulation (PBR) that will be in effect for the LDCs for a maximum of three years, until the 2010 rate year. This PBR, which became effective on May 1, 2007, comprises an Inflation factor minus a Productivity factor of about 1%, as well as an additional adjustment for the recovery of one-time costs. No major financial impact for the distributors is expected, apart from a marginal increase in revenues due to the inflation factor generally being slightly higher than the productivity factor. ROE was set at 9%, the same as in 2006.
  - For the next three years, OEB will be re-basing the rates with a full cost-of-service proceeding for all LDCs. The roughly 90 LDCs will be divided into three groups. The first group will be re-based in 2008 with the 3rd Generation Incentive Rate mechanism applied in succeeding years, up to the 2010 rate year. The 3rd Generation Incentive Mechanism is expected to be materially similar to the 2nd Generation Incentive Mechanism. By 2010, all electricity distributors in Ontario will have undergone a re-basing of rates with a full cost-of-service proceeding.
  - Enersource has been selected by the OEB to be in the first group of distributors to go through re-basing, in 2008.
  - Starting May 1, 2008, all distributors will be required to transition to a single deemed capital structure (60%/40%) over a three-year period. This will have no impact on EHM as its capital structure is already set at 60%/40%.
- EHM is part of a coalition of six, large, electricity distributors within the province that are launching a significant Smart-Meter initiative to fulfill the provincial government's plan for the installation of 800,000 Smart Meters throughout the Province by the end of 2007. The costs associated with the implementation will be recovered through the imposition of a rate adder and the maintenance of a capital-variance account that will incorporate return-on-investment and amortization components, as well as an Operations Maintenance & Administration (OM&A) variance account that will reflect actual amounts spent plus carrying costs.

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EARNINGS AND OUTLOOK

	For the year ended December 31				
($ millions)	2006	2005	2004	2003	2002
Net operating revenues	122.4	117.8	101.6	103.7	97.5
Operating costs	84.4	80.1	73.3	72.3	65.9
EBITDA	75.5	75.0	62.8	61.4	59.0
EBIT	38.0	37.7	28.2	31.3	31.7
Net Interest expense	15.4	15.8	13.3	16.6	17.6
Net income (before discont. operations)	12.6	12.8	9.8	7.1	12.2
Discontinued operations	3.9	0.7	1.9	0.5	(1.4)
Reported Net income	17.2	13.4	11.7	7.6	10.8

Summary

- Overall, EBIT and earnings have trended upwards since F2004, primarily due to distribution rate increases and a rise in electricity consumption. The financial impact of the increased rates and consumption was partially offset by higher operating costs.
  - Earnings are almost entirely derived from regulated electricity-distribution activities.
- For F2006, the increase in distribution revenue resulting from the increase in distribution rates was partially offset by a 5% decline in electricity consumption due to a 29% reduction of cooling degree days during the summer months and an 11% reduction of heating degree days during the winter months, relative to F2005.
- Interest expense has remained relatively stable on a constant amount of debt.
- Electricity prices do not directly impact on earnings since the costs are passed through to customers.

Outlook

- EBIT is expected to increase moderately in F2007 as this will be Enersource's first rate year under the PBR. The moderate growth in EBIT will be primarily due the OEB's two decisions made in 2006.
  - The earnings will also grow at a pace that follows the growth rate in Enersource's service area.
- EBIT for F2008 and beyond will depend largely on the 2008 re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations at EHM, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.
  - Regulated distribution operations are expected to comprise over 95% of consolidated EBIT going forward.
  - Future earnings contribution from its non-regulated subsidiary, Enersource Services, is less certain than from regulated distribution at EHM. However, it is expected that the contributions from non-regulated operations to earnings will continue to be minimal.

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FINANCIAL PROFILE

Statement of Changes in Cash Flow	For the year ended December 31				
(CAD millions)	2006	2005	2004	2003	2002
Net income (before discont. ops.)	12.6	12.8	9.8	7.1	12.2
Depreciation	37.9	37.7	34.6	30.1	27.3
Other non-cash items	0.5	0.1	0.5	2.5	(0.9)
Cash Flow From Operations	50.9	50.6	44.8	39.7	38.6
Common dividends	(8.9)	(8.9)	(15.7)	-	-
Capital expenditures (net of contrib.)	(35.9)	(30.2)	(27.5)	(32.9)	(37.9)
Free Cash Flow Bef. Work. Cap. Changes	6.1	11.5	1.5	6.8	0.8
Changes in working capital	(38.1)	26.6	(12.2)	38.7	(28.4)
Net Free Cash Flow	(32.0)	38.1	(10.7)	45.5	(27.7)
Acquisitions/divestitures	25.1	0.1	0.3	0.0	0.1
Additions to regulatory assets	1.7	(4.2)	(8.2)	4.8	(17.2)
Deposits and prudentials	0.6	5.8	2.6	2.3	5.3
Cash flow before financing	(4.5)	39.8	(16.1)	52.7	(39.6)
Customer Deposits	(0.6)	(5.8)	(2.6)	(2.3)	(5.3)
Net debt financing	-	-	-	-	-
Net equity financing	-	-	-	-	-
Net Change in Cash Bef. Discont. Ops.	(5.1)	34.0	(18.6)	50.3	(44.8)
Discontinued Operations	1.2	0.1	0.4	-	-
Other	-	0.1	-	-	-
Net Change in Cash	(3.8)	34.2	(18.2)	50.3	(44.8)

Key Financial Ratios					
Total debt-to-capital	58.0%	59.0%	59.6%	59.1%	60.4%
EBITDA interest coverage (times)	4.06	4.24	4.15	3.31	3.20
EBIT interest coverage (times)	2.04	2.13	1.86	1.69	1.72
Cash flow/total debt	17.6%	17.5%	15.5%	13.7%	13.1%
Dividend Payout	51.8%	66.4%	135.1%	0.0%	0.0%

Summary

- Enersource has maintained a strong financial profile, reflecting its solid balance sheet and credit metrics, without needing equity support from its owners.
  - Cash flow from operations has remained more than sufficient to fully fund capital expenditures and dividends since F2002.
- Cash-flow-to-debt and interest coverage ratios have improved from 2004 levels and continue to support the "A" rating.
- The large swings in working capital are mainly due to changes in the balance of unbilled revenue and accounts receivable.
- A reduced dividend-payout ratio is primarily responsible for the moderately improved debt-to-capital ratio of 58%.
- Asset sale proceeds of $25 million in F2006 stemmed from the sale of water heating and telecom assets.

Outlook

- Cash flow from operations is expected to increase moderately, along with earnings in 2007.
- The Company will likely incur a very modest free cash flow deficit due to a heightened capital expenditure program.
  - Capital expenditures are expected to be in the $50 million range going forward.
  - The OEB has identified LDCs as the source of funding for the supply and installation of the Smart Meters across Ontario. The first phase requires 800,000 Smart Meters to be installed throughout the province by December 31, 2007. The company expects to recover the costs

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associated with the implementation via the imposition of a Smart Meter rate adder, maintenance of a capital-variance account that incorporates return on investment and amortization components and an OM&A variance account that will reflect actual amounts spent plus carrying costs. However, the timing on cash flows of Enersource is uncertain at this time. Enersource is expected to spend approximately $9 million on Smart Meters in 2007.

- Regulatory asset recovery is expected to generate an additional $6 million in cash for F2007 and F2008.
- DBRS expects total debt-to-capital to remain near 60% over the medium to longer term.
  - Hence, cash flow-to-debt and interest coverage ratios are expected to remain at a level appropriate to support the "A" rating.

LONG-TERM DEBT MATURITIES AND BANK LINES

Summary

- Enersource's long-term debt currently consists entirely of a $290 million private placement with Borealis Infrastructure Trust. In the event of default, Borealis Infrastructure Trust has a first-ranking security interest on Enersource's equity interest in EHM.
  - Interest rate: 6.29%
  - Maturity: May 2011
- Enersource currently has access to the following unsecured bank-credit facilities:
  - $50 million revolving demand facility
  - $20 million non-revolving demand facility
  - $5 million revolving lease line of credit
- The $50 million revolving demand facility and the $5 million revolving lease line of credit were fully available as at December 31, 2006.
- Of the $20 million non-revolving demand facility, $16.6 was used for prudential postings with the Independent Electricity System Operator (IESO) as at December 31, 2006.

Outlook

- The Company's liquidity position is strong, reflecting the unutilized credit facility, stable cash flow from operations, zero short-term obligations, and a significant cash position.
- No new long-term debt requirements are expected over the medium term.
- Working capital requirements would be funded with the Company's operating line.

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Enersource Corporation

Income Statement	For the year ended December 31				
(CAD millions)	2006	2005	2004	2003	2002
Residential	150.0	144.9	121.5	119.4	143.6
Commercial	371.1	435.6	358.3	357.2	412.1
Large users	66.5	84.1	68.4	71.5	68.2
Street lighting	1.1	2.2	3.2	2.8	2.7
Retailer Energy Billing	79.9	109.1	73.4	63.2	18.7
Gross electricity revenues	668.6	775.9	624.9	614.2	645.3
Power purchases	557.3	672.4	534.0	525.7	560.7
Net distribution revenues	111.3	103.5	90.8	88.5	84.6
Ancillary revenues	8.8	11.8	8.3	13.0	10.4
Other revenues	2.2	2.5	2.4	2.2	2.5
Net operating revenues	122.4	117.8	101.6	103.7	97.5
Expenses					
Operating + maintenance	40.4	34.1	32.4	42.2	38.6
Allocated costs	6.6	8.7	6.4	-	-
Depreciation	37.4	37.3	34.6	30.1	27.3
Total operating expenses	84.4	80.1	73.3	72.3	65.9
Operating income	38.0	37.7	28.2	31.3	31.7
Interest expense	18.6	17.7	15.2	18.6	18.5
Non-cash financial charges	-	-	-	-	-
Interest income	(3.2)	(1.9)	(1.8)	(1.9)	(0.8)
Net interest expense	15.4	15.8	13.3	16.6	17.6
Pre-tax income from Cont. ops	22.5	21.9	14.9	14.7	14.0
Income taxes	9.9	9.1	5.1	7.6	1.9
Net income before minority	12.6	12.8	9.8	7.1	12.2
Gain (loss) on disposal of assets	0.7	(0.1)	-	-	-
Minority interest/Discont. ops.	3.9	0.7	1.9	0.5	(1.4)
Net income	17.2	13.4	11.7	7.6	10.8

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Balance Sheet ($ millions)	As at December 31				As at December 31		
Assets	2006	2005	2004	**Liabilities & Equity**	2006	2005	2004
Cash	56.9	60.7	26.5	Short-term debt	-	-	-
A/R + unbilled revenue	116.2	122.0	102.1	A/P + accrueds	88.5	130.3	88.6
Inventories	5.6	5.0	4.3	Taxes payable	3.1	6.7	1.4
Other	1.7	2.9	0.9	**Current Liabilities**	91.5	137.0	90.0
Current Assets	180.4	190.6	133.9	Customer deposits	21.7	22.4	28.1
Net fixed assets	399.5	416.6	417.9	Long-term debt	290.0	290.0	290.0
Regulatory assets	12.2	21.0	24.4	Other	2.7	2.1	2.0
Deferred charges	1.9	2.3	2.7	Minority interest	0.2	0.2	0.2
Customer deposits	21.7	22.4	28.1	Shareholders' equity	209.5	201.2	196.7
Total	615.7	652.9	607.0	**Total**	615.7	652.9	607.0

Ratio Analysis	For the year ended December 31				
Liquidity Ratios	2006	2005	2004	2003	2002
Current ratio	1.97	1.39	1.49	1.52	1.41
Accumulated depreciation/fixed assets	44.9%	43.7%	41.2%	38.9%	36.9%
Total debt-to-capital	58.0%	59.0%	59.6%	59.1%	60.4%
Net debt-to-capital	52.6%	53.2%	57.2%	54.9%	60.4%
Cash flow/total debt	17.6%	17.5%	15.5%	13.7%	13.1%
Cash flow/net debt	21.8%	22.1%	17.0%	16.2%	13.1%
Cash flow/capital expenditures (1)	1.42	1.67	1.63	1.21	1.02
Average coupon on long-term debt	6.29%	6.29%	6.29%	6.29%	6.29%
Common dividend payout	51.8%	66.4%	135.1%	0.0%	0.0%
Deemed equity in the capital structure	40.0%	40.0%	40.0%	40.0%	40.0%
Coverage Ratios					
EBIT interest coverage	2.04	2.13	1.86	1.69	1.72
EBITDA interest coverage	4.06	4.24	4.15	3.31	3.20
Fixed-charges coverage	2.04	2.13	1.86	1.69	1.72
Profitability/Operating Efficiency					
Operating margin	31.1%	32.0%	27.8%	30.2%	32.5%
Net margin (before extras.)	14.0%	11.4%	11.5%	7.4%	11.1%
Return on avg. common equity	8.4%	6.7%	5.9%	3.9%	5.7%
GWh sold/employee (2)	22.8	23.4	23.7	23.2	22.4
Customers/employee (2)	529	522	546	530	502
OM&A/avg. customer ($)	260.8	241.2	221.0	246.0	231.4
Rate base	474.4	451.0	451.0	451.0	451.0
Electricity Throughputs					
Residential	1,539.2	1,639.0	1,485.9	1,522.2	1,584.8
Commercial	5,289.6	5,356.6	5,175.4	5,037.7	5,006.2
Large users	966.1	961.5	990.4	996.5	952.1
Street lighting	38.4	39.3	37.9	37.2	39.4
Total (millions kWh)	7,833.3	7,996.4	7,689.6	7,593.6	7,582.5
Growth in electricity throughputs	-2.0%	4.0%	1.3%	0.1%	4.6%
Number of Customers					
Residential	161,165	157,903	156,410	153,733	149,822
Commercial	20,699	20,235	20,453	20,120	19,829
Large users	9	8	8	10	10
Street lighting	1	1	1	1	1
Total	181,874	178,147	176,872	173,864	169,662
Growth in customer base	2.1%	0.7%	1.7%	2.5%	3.7%
Unit Revenues & Costs	(cents per kWh throughputs)				
Average gross revenues	8.54	9.70	8.13	8.09	8.51
Power costs	7.11	8.41	6.95	6.92	7.39
Average net revenues	1.42	1.29	1.18	1.17	1.12
Variable costs (OM&A)	0.73	0.65	0.57	0.66	0.53
Fixed costs (deprec., interest, gov't levies)	0.67	0.66	0.62	0.62	0.59
Total costs (excl. power costs)	1.40	1.31	1.19	1.27	1.13
Net margin (excl. interest income, ancillary revenues)	0.16	0.16	0.13	0.09	0.16

(1) Net of customer contributions.

(2) # of employees for F2006 is as at Sep 30, 2006.

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Note:
All figures are in Canadian dollars unless otherwise noted.

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DBRS *Insight beyond the rating.*

Hydro Ottawa Holding Inc.

RATING

Debt Rated	Rating Action	Rating	Trend
Senior Unsecured Debt	Trend change	A (low)	Positive

RATING HISTORY	Current	2006	2005	2004	2003	2002
Senior Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A	NR

Ratings prior to 2005 reflect Hydro Ottawa Holding Inc.'s Issuer rating.

RATING UPDATE

DBRS has changed the trend on the Senior Unsecured Debt of Hydro Ottawa Holding Inc. (Hydro Ottawa or the Company) to Positive from Stable. The trend change reflects Hydro Ottawa's continuing improvement in its financial metrics driven by strong operational performance combined with a low level of business risk underpinned by its regulated electricity distribution business.

Hydro Ottawa's financial metrics have shown considerable improvement since 2004, largely benefiting from the strong financial performance of its regulated distribution business, the recapitalization of $37.8 million in debt to equity by the City of Ottawa (the City) in 2004 and a lower interest rate of 4.93% on the $200 million in long-term debt that was issued in 2005 to repay a 6.9% promissory note to the City. DBRS anticipates the overall growth rate in earnings to subside modestly, but remain reasonable over the medium term, as Hydro Ottawa Limited's (Hydro LDC) revenue requirement is re-based in 2008, combined with higher earnings contributions from its non-regulated operations.

The regulatory environment in Ontario continues to improve. In April 2006, the Ontario Energy Board (OEB) approved an increase in Hydro Ottawa's rate base from $380 million (from 1999 to 2005) to $504 million in 2006, representing a 33% increase, which will continue to underpin earnings and cash flow growth. (Continued on page 2)

RATING CONSIDERATIONS

Strengths

- Regulated electricity distribution has low business risk and provides long-term stability to earnings and cash flows
- Strong franchise area with high density population and diversified customer base
- Strong credit metrics and balance sheet
- Low cost provider/operational efficiency
- Cautious approach to growth of non-regulated businesses

Challenges

- Significant capital expenditures
- Approved ROE sensitive to long-term interest rates
- Earnings sensitive to volumes of electricity sold
- Unable to access equity capital markets

FINANCIAL INFORMATION

	For the year ended December 31				
	2006	2005	2004	2003	2002
Total debt (CAD millions) (1)	255.6	213.4	231.9	248.5	245.1
Total adjusted debt in capital structure (%) (1)	47.5%	45.7%	50.1%	58.9%	58.9%
Cash flow/total adj. debt (%) (1)	23.4%	24.0%	16.3%	12.5%	13.4%
Cash flow/capital expenditures (times) (2)	0.76	0.82	0.54	0.41	1.17
EBIT interest coverage (times) (1)	3.57	2.91	1.62	1.35	1.86
EBIT (CAD millions)*	41.7	32.8	27.6	23.1	20.7
Cash flow from operations (CAD millions)	59.8	51.2	37.8	31.1	32.7
Core net income (CAD millions)*	19.3	15.7	8.9	4.3	7.8
Return on average equity (before extras.)	7.2%	6.5%	4.4%	2.5%	4.4%
Electricity throughputs (GWh)	7,466	7,663	7,515	7,483	7,471

*Adjusted to exclude recovery on regulatory asset provisions. (1) DBRS adjusted for operating lease debt and interest expense equivalents.
(2) Capital expenditures net of customer contributions.

THE COMPANY

Hydro Ottawa Holding Inc. is a holding company which wholly-owns the following subsidiaries: (1) Hydro Ottawa Limited (Hydro LDC), a regulated electricity distributor (Hydro Ottawa's primary business); (2) Energy Ottawa Inc., a non-regulated power generation company involved in energy management and procurement services; and (3) Telecom Ottawa Holding Inc. which is involved in fibre-optic leasing, internet service provider (ISP), virtual network provider and data local exchange carrier. Hydro Ottawa Holding Inc.'s is wholly owned by the City of Ottawa (the City), rated AA (high).

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RATING UPDATE (Continued from page 1).

In addition, the OEB approved the recovery of regulatory assets of $36.4 million of which $22.5 million had been recovered previously, leaving $13.9 million to be recovered over a two year period ending April 2008.

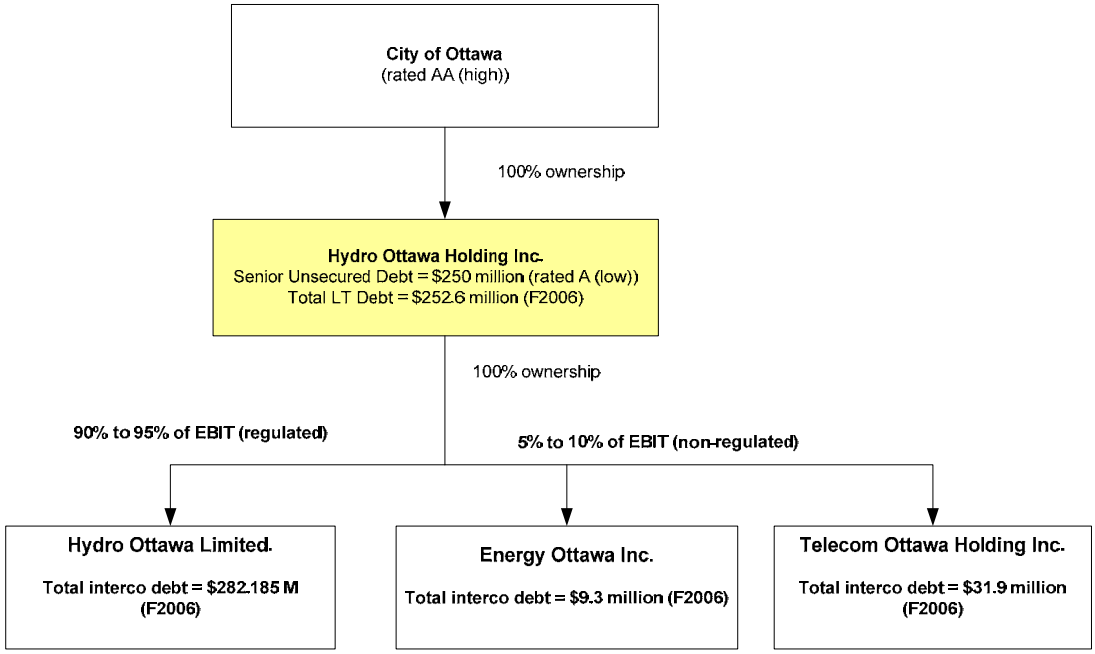
The OEB's new regulatory framework under the 2nd Generation Incentive Regulation Model (IRM) and Cost of Capital is viewed by DBRS as reasonable, providing sufficient earnings and cash flow stability. In the latter half of 2007, DBRS expects Hydro LDC to file a rate application for a mid-year rate adjustment in 2008, outlining its capital plan while addressing the additional capital investment currently not included in its rate base.

The Company's planned capital investment is expected to increase modestly from present levels, to meet demand growth and to further strengthen its distribution system. Capital expenditures are projected to be in the range of $80 million to $90 million per annum ($70 million net of customer contributions), which are likely to result in manageable free cash flow deficits. These deficits will be financed through drawings under the Company's $150 million bank facility ($75 million permitted for capital expenditures) and then refinanced with longer-term debt. As a result, DBRS believes that leverage will increase modestly, relative to current levels, to a longer-term range of 50% to 55%, which will put modest pressure on cash flow-to-debt and interest coverage ratios.

However, despite some anticipated weakening in the Company's financial metrics, Hydro Ottawa's credit profile will continue to support the Positive Trend given its robust balance sheet and strong credit metrics, accompanied by a modestly improving regulatory environment.

DBRS will continue to monitor the Company, and would consider an upgrade to the Senior Unsecured Debt rating if Hydro Ottawa continues to exhibit strong financial results and maintains its conservative financial and operating strategies including the managed growth of its non-regulated operations.

CORPORATE STRUCTURE



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RATING CONSIDERATIONS

Strengths

(1) Hydro Ottawa is predominately a regulated electric distribution focused business (approximately 90% of total EBIT) and operates in a modestly improving regulatory environment. DBRS views the new regulatory framework under the 2nd Generation IRM and Cost of Capital as reasonable, providing sufficient earnings and cash flow stability. DBRS expects the OEB will be supportive in the recovery of capital costs and regulatory assets.

(2) Hydro Ottawa's is one of the largest municipally owned local distribution companies (LDCs) in Ontario, serving the densely populated areas within the City of Ottawa and the Village of Casselman. The majority of Hydro LDC's electricity sales are to residential customers, the federal government, and the MUSH sector (municipal, universities, schools and hospitals), which have relatively stable demand year-over-year, as these customers are less sensitive to economic cycles.

(3) Hydro Ottawa's credit metrics have improved steadily since 2004 and remain solid for a utility that benefits from low level of business risk, and are strong for the current ratings: debt/capital ratio at 47.5%, EBIT interest coverage at 3.57 times, and cash flow-to-debt at 23.4%. DBRS notes that debt levels will trend higher over the longer term, as the Company continues to incur free cash flow deficits. However, the robust balance sheet and strong coverage ratios would allow the Company to easily absorb some incremental debt. DBRS believes the financial metrics will remain within a range consistent with the assigned rating.

(4) Hydro Ottawa continues to exceed OEB service level targets and boasts one of the lowest distribution rates in the province, which underscores its prudent cost management principles.

(5) Hydro Ottawa continues to manage the growth of its non-regulated operations within an acceptable risk profile. Recently, Telecom Ottawa shed its unprofitable business lines and returned to the basics, which is broadband capacity enhanced to carrier grade quality level. Telecom Ottawa requires modest capital investment as most of the fibre infrastructure is already in place. Energy Ottawa, the electricity generation operation, provides both earnings growth and diversification opportunities. Energy Ottawa's objective is to minimize its commodity price risk by entering into long-term contracts, for up to 80% of total output. DBRS notes the Company will only develop generating projects with a long-term purchase power agreement in place.

Challenges

(1) The Company is in the middle of a heavy capital investment cycle to enhance the reliability of the system and to meet growing demographic demands. Over the medium term, DBRS expects capital expenditures in the range of $80 million to $90 million ($70 million net of customer contributions), which, combined with dividends, is expected to exceed operating cash flow by approximately $25 million to $35 million per year. These free cash flow deficits will place modest pressure on the balance sheet and coverage ratios.

(2) Regulatory-approved ROE levels are low and could continue to decline if the longer-term interest rates decline. The ROE of 9.0% in 2007 (2006-9.0%) is an 88 basis point decline from 9.88% in 2005. However, the earnings impact from a lower ROE level is offset by the recent 33% increase in Hydro LDC's rate base from $380 million (from 1999 to 2005) to $504 million in 2006.

(3) Earnings and cash flows for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather patterns directly impact the volume of electricity sold, and hence, revenue earned from electricity sales.

(4) Due to municipality ownership, Hydro Ottawa is unable to access the equity capital markets. This limits the Company's financial flexibility, as free cash flow deficits will be financed through its revolving credit facilities ($150 million) or debt issuance. Furthermore, Hydro Ottawa's dividend policy with the City (a target of 60% of previous year's consolidated net income) will further increase liquidity needs during this investment cycle.

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REGULATION

Hydro Ottawa's electricity distribution operations are regulated by the Ontario Energy Board (OEB) under the Ontario Energy Board Act, 1998 (the OEB Act), as modified by the following noteworthy amendments:

- The Electricity Pricing, Conservation and Supply Act, 2002 (Bill 210) – December 9, 2002.
- The Ontario Energy Board Amendment Act (Electricity Pricing), 2003 (Bill 4) – December 18, 2003.
- The Electricity Restructuring Act, 2004 (Bill 100) – December 9, 2004.

Currently, Hydro Ottawa operates under a performance-based incentive mechanism with a deemed ROE of 9.0%, based on a forward looking cost-of-service for the mid-year rate decision. The purchased power included in rates is a flow through to consumers determined by the OEB based on a blend of fluctuating, fixed and capped prices paid to generators under the Regulated Price Plan (RPP). The RPP is based on a forecast of expected costs over the next 12 months. If the cost of supplying electricity differs from what was forecast, the OEB may readjust electricity prices accordingly in the next price period (usually a six month time frame), in order to true up the RPP prices with the prices paid to generators.

In April 2006, the OEB increased Hydro Ottawa's distribution rates for the period May 1, 2006 to April 30, 2007, resulting in a 1.9% increase in total electricity bills. The methodology used by the OEB to establish the distribution rates was based on a rate base of $504 million ($380 million from 1999 to 2005), a deemed debt-to-equity structure of 60-40, approved debt rate of 5.25%, and an allowed ROE of 9.0%. Furthermore, the OEB approved the recovery of $36.4 million of regulatory assets, of which $22.5 million had been recovered previously, leaving $13.9 million to be recovered through distribution rates over a two year period ending in April 2008.

On December 20, 2006, the OEB issued a 2007 rate adjustment model (2nd Generation Incentive Regulation Model) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. As a result, base distribution rates, exclusive of rate riders, were adjusted formulaically to reflect an allowance for inflation of 1.9%, a fixed productivity offset of 1.0%, and removal of the federal large corporation tax. As such, there was no major financial impact for distributors, only a marginal increase in revenues due to the inflation factor generally being slightly higher than the productivity factor. In each of three subsequent years, approximately one-third of the electricity distributors will have their distribution rates reviewed and reset by the OEB through a cost-of-service-type of rate proceeding. LDCs rebased in 2008 will be subject to an Incentive Rate Mechanism applied in succeeding years up to the 2010 rate year. By 2010, all electricity distributors in Ontario will have undergone a re-basing of rates.

The net effect of the OEB decision in 2007, exclusive of smart meter adjustments, was to provide for approximately a 0.43% increase in base distribution rates to all customer classes for May 1, 2007 to April 30, 2008 period. To note, as of May 1, 2007, Hydro Ottawa is collecting a rate of $1.74 per month from all metered customers as part of the delivery charge on their bill, related to the implementation of the province's Smart Meter Program.

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EARNINGS AND OUTLOOK

Earnings and Outlook *	For the year ended December 31				
(CAD millions)	2006	2005	2004	2003	2002
Net distribution revenues	119.5	97.9	89.8	94.6	87.7
Other revenues	24.9	22.8	22.2	18.3	9.2
Net revenues	**144.4**	**120.7**	**112.0**	**112.8**	**97.0**
Operating expenses	102.7	87.9	84.4	89.7	76.3
EBITDA	80.7	67.0	57.3	50.2	45.8
EBIT	41.7	32.8	27.6	23.1	20.7
Net interest expense	11.6	11.2	15.7	16.2	10.2
Payments in lieu of taxes (incl. capital taxes)	10.9	5.9	3.0	2.6	2.6
Net income bef. extra./non-recurring items	19.3	15.7	8.9	4.3	7.8
Regulatory asset recovery/non-recurring items	21.1	6.9	10.8	(1.7)	(20.4)
Reported net income	40.4	22.6	19.7	2.6	(12.6)
Operating margin	29%	27%	25%	20%	21%

*Adjusted to exclude recovery on regulatory asset provisions.

EBIT by subsidiary *						
(CAD millions)		2006	2005	2004	2003	2002
Hydro Ottawa Limited	96%	40.05	29.4	26.8	22.76	17.52
Energy Ottawa Inc.	9%	3.89	4.8	1.6	2.1	3.85
Telecom Ottawa Holdings Inc.	2%	0.78	(0.38)	0.28	(0.77)	(0.55)
Hydro Ottawa Holdings Inc. (non-cons.)	-7%	(2.98)	(1.03)	(1.07)	(1.03)	(0.16)
Hydro Ottawa Holdings Inc. (consolidated)		**41.74**	**32.83**	**27.57**	**23.07**	**20.66**

*Adjusted to exclude recovery on regulatory asset provisions.

Summary

Earnings, as measured by EBIT, continued to register solid year-over-year growth, driven primarily by the performance of the Company's regulated electric distribution business which accounts for approximately 95% of total EBIT.

- DBRS notes the significant uptick in the Company's' earnings for F2006 was largely reflective of the following catalyst:
  - The April 2006 rate decision, which resulted in a 33% increase in Hydro LDC's rate base, with a corresponding 1.9% increase in total electricity bills.
  - Continued demographic and weather related throughput growth in service area.
  - Strong operating efficiency underscored by the upward trend in its operating margin from 20% in 2003 to 29% in 2006.
- Interest expense has decreased substantially since 2004, attributed by the recapitalization of $37.8 million in debt to equity by the City in 2004, and a lower interest rate of 4.93% on the $200 million in long-term debt that was issued in 2005 to repay a 6.9% promissory note to the City.
- Reported net income increased by 70% from $22.6 million in F2005 to $40.4 million in F2006, largely benefiting from OEB approval to recover regulatory assets of $36.4 million, combined with the 1.9% increase in its distributions rates.

Overall, the steady upward trend in earnings over the past five years is largely attributable to Hydro Ottawa's favourable and growing franchise area, as well as modest distribution rate increases and recovery of regulatory assets.

Outlook

DBRS anticipates slower but modest EBIT growth over the medium term, as Hydro Ottawa will likely file its rate application for rebasing in 2008 rate year, combined with increased earnings from non-regulated operations.

- Hydro Ottawa will have its distribution rates reviewed and reset through a forward looking cost of service type rate proceeding in 2008 with an IRM applied in succeeding years up to 2010. The rate base should reflect the significant capital expenditures over the next few years.
- DBRS anticipates the recovery of regulatory assets through distribution rates over the near term (approximately $13.9 million).
- Energy Ottawa is committed to implementing a more prudent pricing strategy by locking in up to 80% of production under long-term fixed price contracts. In January 2007, the Company successfully commissioned the TrailRoad generation facility (5 MW) with the output sold under a 20-year PPA with the OPA.

Over the long term, the Company's regulated electricity distribution operation and generation output sold under fixed price contracts will continue to provide a high degree of stability to earnings and cash flows.

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FINANCIAL PROFILE

Statement of Cash Flows	For the year ended December 31				
(CAD millions)	2006	2005	2004	2003	2002
Net income before extraordinary items	19.3	15.7	8.9	4.3	7.8
Depreciation	38.9	34.1	29.8	27.2	25.2
Other non-cash adjustments	1.6	1.3	(0.9)	(0.4)	(0.3)
Cash Flow From Operations	**59.8**	**51.2**	**37.8**	**31.1**	**32.7**
Capital expenditures (net of customer contributions)	(78.4)	(62.1)	(69.8)	(75.6)	(27.9)
Total dividends paid	(12.00)	0.00	0.00	0.00	0.00
Free Cash Flow Before Working Capital Changes	**(30.5)**	**(10.9)**	**(32.0)**	**(44.5)**	**4.8**
Working capital changes	(35.8)	27.5	(7.1)	43.9	(56.8)
Net Free Cash Flow	**(66.3)**	**16.5**	**(39.1)**	**(0.6)**	**(52.0)**
Acquisitions	0.0	0.0	(0.0)	(1.2)	(1.5)
Divestitures	0.7	0.1	0.2	0.5	-
Regulatory asset recovery (provisions) (2)	22.9	7.8	7.0	(3.6)	(20.2)
Other investing / non-recurring	(1.4)	(1.9)	11.2	0.7	0.0
Cash flow before financing	**(44.0)**	**22.5**	**(20.8)**	**(4.2)**	**(73.7)**
Net change in debt	40.9	(20.9)	21.2	3.4	5.3
Net other financing (3)	3.5	(1.6)	(0.4)	0.8	3.3
Net change in cash	**0.4**	**(0.0)**	**0.0**	**0.0**	**(65.1)**
Key Financial Ratios					
Total adjusted debt (1)	255.6	213.4	231.9	248.5	245.1
Total adjusted debt -to-total capital (%) (1)	47.5%	45.7%	50.1%	58.9%	58.9%
Cash flow/capital expenditures (times)	0.76	0.82	0.54	0.41	1.17
Cash flow/total adj. debt (%) (1)	23.4%	24.0%	16.3%	12.5%	13.4%
EBIT gross interest coverage (times) (1)	3.57	2.91	1.62	1.35	1.86
Dividend payout ratio	62%	0%	0%	0%	0%

(1) DBRS adjusted for operting lease debt and interest expense equivalents. (2) Recovery on regulatory asset provisions. (3) Customer deposits.

Summary

Despite the notable improvement in Hydro Ottawa's financial profile and operating cash flow, the Company continued to record free cash flow deficits, given the large capital expenditure program and recent adoption of a dividend policy with the City (with a target of 60% of previous year's net income).

- The recent uptick in capital expenditures, coupled with dividends, has resulted in a larger free cash flow deficit for F2006.
- Hydro LDC continued to recover regulatory assets through distribution rates, which provide additional cash flows for distribution system capital spending.
- The notable swings in working capital are mainly due to the timing of the Company receiving and paying customer rebates (pass through of the commodity cost of electricity) from the Independent Electric System Operator (IESO).
- Key credit metrics have improved from 2004 levels, as debt levels have modestly increased offset by a growing equity base and lower interest expense on outstanding debt, which remain solidly within the current rating category for a low-risk electric distribution utility with debt to capital at 47.5%, EBIT interest coverage at 3.57 and cash flow-to-debt at 23.4%.

Outlook

Cash flow from operations is expected to increase moderately, along with earnings over the medium term. However, cash flows will remain insufficient to fund heightened capital investment program and distribution to the City.

- Hydro Ottawa anticipates capital expenditures in the range of $80 million to $90 million over the next five years, with majority related to the regulated distribution business (approximately 80%), split fairly evenly between improving system reliability and meeting growth demands.
- The current dividend policy will increase liquidity needs over the medium term as the Company is committed to investing heavily in the distribution system.
- As such, the Company is expected to incur manageable free cash flow deficits in the average range of $25 million to $35 million per annum, which will be financed through its $150 million three year revolving credit facility, of which, $75 million is available for capital expenditures. DBRS notes that short-term financing through existing credit facilities

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will reduce financial flexibility to absorb an unanticipated event.

- Hydro Ottawa is expected to file a cost-of-service rate application for mid-rate year 2008. This should provide for some operating cash flow growth, as invested capital is added to the rate base thereby increasing the earnings profile.
- The Company's leverage is expected to increase modestly over the medium term, as the large capital expenditure program and stipulated dividend policy will result in free cash flow deficits. These deficits and the subsequent higher leverage in the capital structure – between a longer-term range of 50% to 55% – will modestly pressure cash flow-to-debt and interest coverage ratios, from current levels, but a measurable change in the Company's financial profile is not expected, with credit metrics remaining favourable.

LONG-TERM DEBT MATURITIES AND BANK LINES

Credit facilities (CAD millions)	Amount	Drawn	Available	Expiration
Three-year, extendible, revolving credit facility	150	22	128	1/6/2008
364-day revolving term operating credit line	25	0	25	6/30/2007*
Total consolidated credit facilities	**175**	**22**	**153**	
Notes Payable (CAD millions)		**Int. rate**	**Amount**	**Maturity**
Senior unsecured debentures, Series 2005- 1		5%	200.00	2/9/2015
Senior unsecured debentures, Series 2006-1		5%	50.00	12/19/2036
Integrated Gas Recovery Services Inc. (IGRS)		0%	2.64	
Total		**4.9%**	**252.6**	

*DBRS expects the line of credit to be renewed shortly.

Long-Term Debt

Hydro Ottawa finances its operations and capital expenditures with long-term debt (senior unsecured $250 million outstanding at December 31, 2006) and revolving credit facilities ($175 million). The debt-to-capital ratio is 47.5%, which is moderately more conservative than the recently adjusted regulatory approved level of 60%.

- DBRS notes that the Company has no debt maturing over the medium term.
- Given that Hydro Ottawa is an infrequent issuer, the Company demonstrated good access to the debt capital market with the December 2006, issuance of $50 million Senior Unsecured Debentures (30 year at 4.98%).
- The trust indenture contains the following covenants for the Series 2005 and 2006 debentures:
  - Any additional indebtedness is subject to a 75% capitalization ratio test.
  - Negative pledge clause.
  - Restrictions on asset sales and amalgamations.
- The Integrated Gas Recovery Services Inc promissory note for $2.64 million was issued to fund the construction of the gas collection and generation plant at the TrailRoad landfill site. Pursuant to the Shareholder Agreement dated November 3, 2005 among Energy Ottawa and PowerTrail, the note is non-interest bearing, and subject to certain conditions stipulated in this agreement.

Liquidity

Liquidity requirements will modestly increase over the medium term to accommodate higher capital expenditures, regulatory working capital needs, and dividend payments to the City. DBRS notes Hydro Ottawa has reasonable liquidity with $153 million unused capacity under the Company's $175 million credit lines at the end of December 31, 2006.

- DBRS notes that the three year revolving credit facility contains customary covenants, in which requirements to maintain the consolidated debt-to-capitalization ratio at or below 75% and use no more than $75 million of this facility to fund capital expenditures.

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APPENDIX

Hydro Ottawa Holding Inc.

Balance Sheet
(CAD millions)

	As at December 31				As at December 31		
Assets	2006	2005	2004	**Liabilities & Equity**	2006	2005	2004
Cash & s.t. investments	0	-	-	Short-term debt	0.0	11.1	29.9
Accounts receivable	56.7	48.2	49.8	A/P + accr'ds	126.5	137.4	109.0
Unbilled revenue	81.8	96.0	81.0	L.t.d. due in one yr.	-	-	200
Inventories	7.3	6.7	8.6	**Current Liabilities**	126.5	148.5	338.9
Other	8.0	1.7	1.2	Customer deposits	5.8	6.3	3.5
Current Assets	154.2	152.6	140.5	Regulatory liability	7.6	16.3	9.6
Regulatory assets (net)	15.4	6.6	5.5	Other liabilities	9.7	8.2	4.7
Net fixed assets	510.1	470.3	440.1	Long-term debt	252.6	200.4	0.0
Other assets	4.8	4.4	1.8	Shareholders' equity	282.2	254.2	231.3
Total	684.4	633.8	587.9	**Total**	684.4	633.8	587.9

	For the year ended December 31				
Ratio Analysis *					
Liquidity Ratios	2006	2005	2004	2003	2002
Current ratio	1.22	1.03	0.41	1.22	1.72
Total adjusted debt in capital structure (%) (1)	47.5%	45.7%	50.1%	58.9%	58.9%
Cash flow/total adj. debt (1)	23.4%	24.0%	16.3%	12.5%	13.4%
Debt/EBITDA	3.17	3.19	3.95	4.86	5.26
Cash flow/capital expenditures (2)	0.76	0.82	0.54	0.41	1.17
Deemed equity	40%	40%	40%	40%	40%
Common dividend payout	62.3%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios					
EBIT interest coverage (1)	3.57	2.91	1.62	1.35	1.86
EBITDA interest coverage (1)	6.89	5.93	3.35	2.93	4.12
Profitability/Operating Efficiency					
Operating margin	28.9%	27.2%	24.6%	20.5%	21.3%
Net margin (before extras.)	13.3%	13.0%	8.0%	3.8%	8.1%
Return on avg. common equity (bef. extras)	7.2%	6.5%	4.4%	2.5%	4.4%
GWh sold/employee	14.8	15.6	15.9	15.2	16.0
Customers/employee	561	567	581	546	565
Customers/distribution lines	52	53	54	56	55
Rate base (CAD millions)	504	380	380	380	380

Electricity Throughputs	2006	2005	2004	2003	2002
Residential	2,226	2,358	2,267	2,241	2,255
Commercial	4,549	4,642	4,590	4,554	4,512
Large users > 5 MW	655	626	621	651	665
Street lighting	36	37	37	36	38
Total (GWh)	7,466	7,663	7,515	7,483	7,471
Growth in electricity throughputs	(2.6%)	2.0%	0.4%	0.2%	-
Peak demand (MW)	1,495	1,465	1,405	1,420	1,445
Generation capacity (MW)	15	15	15	15	15
Gross electricity generated (MWh)	na	103,900	82,000	111,171	92,749
Number of Customers					
Residential	255,993	252,268	247,790	242,370	237,755
Commercial	26,389	26,303	26,240	26,810	26,754
Large users > 5 MW	11	10	10	11	11
Total	282,393	278,581	274,040	269,191	264,520
Growth of customer base	1.4%	1.7%	1.8%	1.8%	na

(1) DBRS adjusted for operating lease debt and interest expense equivalents. (2) Net of customer contributions.

* DBRS adjusted ratios to exclude recovery of regulatory asset provisions.

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Note:
All figures are in Canadian dollars unless otherwise noted.

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Rating Report

Report Date:
November 30, 2007

Previous Report:
August 3, 2006

Ontario Power Generation Inc.

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The Company

Ontario Power Generation Inc. is an electricity generating company with a diverse portfolio of 22,157 MW of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Recent Actions

August 28, 2007
Comments on ABCP Exposure

August 3, 2006
Ratings Confirmed

May 20, 2005
Long-Term Trend Changed to Stable from Under Review with Developing Implications

Authorized Commercial Paper Limit: $1 Billion

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debt*	A (low)	Confirmed	Stable

* Debt held by the Ontario Electric Finance Corporation (OEFC).

Rating Rationale

DBRS has confirmed the Unsecured Debt and Commercial Paper ratings of Ontario Power Generation Inc. (OPG or the Company) at A (low) and R-1 (low), respectively, with Stable trends. The rating confirmations reflect OPG's relatively modest level of business risk stemming from its regulated and non-regulated electric generation operations, stable financial profile underpinned by its robust balance sheet and credit metrics, as well as an improved regulatory environment. However, these factors are offset by the revenue limits on OPG's unregulated generation (which dampens financial performance), the general inability to pass through operating cost increases for both regulated and unregulated assets and by the higher expected capital expenditures that are likely to result in a modest decline in credit metrics. DBRS notes that the ratings on OPG continue to be supported by a sole shareholder, the Province of Ontario (the Province), which is rated AA. The Province supports OPG by providing all of its long-term funding; therefore OPG does not issue any long-term debt in the capital markets. The confirmation is further supported by OPG's limited credit-risk exposure, since its principal counterparty is the Independent Electric System Operator (IESO), a creation of the Province that receives its power through provincial regulation and legislation. (Continued on page 2.)

Rating Considerations

Strengths

(1) Dominant market position in Ontario
(2) Interim regulatory framework favourable to improving OPG's financial profile and strong financial metrics
(3) Nuclear waste management liabilities are limited due to agreement with Province
(4) Support of shareholder (Province of Ontario – rated AA)

Challenges

(1) Higher operating and financial risks associated with nuclear assets
(2) Future decommissioning costs and used fuel-storage above 2.23 million bundles
(3) Interim regulatory framework is less favourable than seen in other North American jurisdictions
(4) Fuel-cost risk associated with coal generation and nuclear to a lesser extent
(5) Political intervention
(6) Significant capital expenditure program

Financial Information

	12 mos. ended	For the year ended December 31			
	Sept. 30, 2007	2006	2005	2004	2003
EBIT interest coverage (times)	3.27	3.70	4.60	0.77	0.90
(Cash flow - n.w.f.*) / CAPEX (times)	1.04	1.43	1.94	0.62	(0.07)
(Cash flow - n.w.f.*) / Total debt	19.4%	24.9%	22.9%	9.3%	(1.2%)
Total debt-to-capital	35.6%	39.0%	43.8%	42.6%	42.6%
Net income (before extras) ($ millions)	404.1	504.1	615.7	54.8	(29.0)
Cash flow from operations ($ millions) **	1,265.1	1,513.1	1,481.7	851.8	482.0
Gross electricity generated (TWh)	104.7	105.2	108.5	105.0	109.1

* n.w.f. = nuclear waste funding. ** DBRS-adjusted.

Rating Rationale (Continued from page 1.)

While provincial ownership and financial support limited downward movement in OPG's ratings during earlier periods of weak financial performance by the Company, the current ratings takes into account OPG's improved financial profile on a stand-alone basis, which has improved due to a more favourable regulatory framework. The financial profile of OPG has improved since 2004, following the announcement of the interim regulated rate structure that came into effect on April 1, 2005. Credit metrics for the 12 months ending September 30, 2007, of 35.6% debt-to-capital, 20% cash flow-to-total debt and 3.27 times EBIT gross interest coverage were well within the range that one would expect for the ratings.

OPG's unregulated generation output accounts for approximately 38% of the Company's total generation output. While unregulated, these generating assets are considered to be of lower risk due to the fact that approximately 85% of their output is sold at the Ontario electricity spot market price, but subject to revenue limits that have been below the market price.

On November 2, 2007, OPG began the pre-submission consultations on its rate application for regulated assets (which account for 62% of OPG's electricity output). The Company intends on finalizing the rate application and submitting it to the Ontario Energy Board (OEB) at the end of November 2007. The application, if approved, would result in a 14% pricing increase from these assets and will result in OPG's first rate increase in three years.

Over the next few years, it is expected that OPG will generate sufficient cash flow from operations to fully fund nuclear waste and decommissioning funding, along with sustaining capital expenditures, but will require a manageable level of debt financing to fund development capital expenditures. Additionally, DBRS would expect the Province to forgo dividends during a period of heightened capital expenditures if necessary to preserve the Company's credit metrics. Cash flow-to-debt and interest-coverage ratios will likely come down modestly from their current levels, but are expected to remain more than adequate to support the current ratings.

There continues to be uncertainty regarding the closure of the Company's coal plants. In August 2007, the Province finalized a regulation that commits to the elimination of coal stations by December 31, 2014. Furthermore, in April and June 2007, the federal and provincial governments introduced climate-change plans and environmental policies with aggressive targets to reduce greenhouse gas emissions. The implications have not yet been determined.

The current ratings reflect all the challenges listed above, combined with the regulatory uncertainty going forward. DBRS notes that the regulatory framework has improved over the past couple of years, but the upcoming rate filing with the OEB will help establish key elements of the regulatory framework that the Company will require in the future, particularly if it undertakes a more aggressive capital expenditure program. Currently OPG's regulated rates are based on a return on equity (ROE) of 5%, which is low in comparison to what the majority of regulated generation companies receive in other jurisdictions in North America. Furthermore, under the existing regulated/price capped units, increases in expenses such as operating and maintenance (O&M) and fuel are generally not recoverable.

Over the long term, the Company is considering a number of potential capital projects, including the refurbishment of Pickering, new nuclear units at Darlington and a number of new hydro facilities. DBRS notes that although these potential capital expenditures could pose several significant financing challenges, the Province would be directly involved in the planning and development process and would be expected to provide financial support if necessary. DBRS notes that while the anticipated capital expenditures are likely to affect financial metrics, the financial support provided by the Province, combined with the improving operating performance from the Company and the upcoming OEB rate filing should support the current ratings going forward.

Ontario Power Generation Inc.

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November 30, 2007

Rating Considerations Details

Strengths

(1) OPG's importance in Ontario is demonstrated by the fact that it is the primary generator in the Province, accounting for about 71% market share of electricity sold in the province. DBRS believes that OPG will continue to be the dominant generator in the province until at least 2014 when the coal-fired generation plants are scheduled to be closed and are replaced by other forms of generation. However, the majority of OPG's assets are now regulated and this proportion will increase when the coal plants are ultimately closed, significantly reducing OPG's influence on unadjusted wholesale electricity prices.

(2) The interim regulatory framework governing OPG has contributed to an improved financial profile compared with the previous Market Power Mitigation Agreement (MPMA), under which OPG has operated since market opening in 2002. The interim framework is expected to result in a weighted-average price of $45/MWh for regulated generation and $46/MWh to $48/MWh on about 85% of output from OPG's non-regulated generating facilities (with certain exceptions). These interim prices compare favourably to the previous average price received on OPG's generation since market opening of about $42.5/MWh. The Company's credit metrics have improved since 2004 and currently support the assigned ratings. At September 30, 2007, credit metrics were strong with 35.6% debt-to-capital, 20% cash flow-to-total debt and 3.27 times EBIT gross interest. OPG will be submitting a rate application to the OEB requesting a 14% price increase on its regulated assets to become effective April 2008.

(3) OPG established and manages, jointly with the Province a Used Fuel Fund (UFF) and a Decommisioning Fund (DF), which are funded by OPG in accordance with the Ontario Nuclear Funds Agreement (ONFA). Under ONFA, the Province guarantees OPG's annual rate of return on the UFF related to the first 2.23 million bundles used. The DF is currently over funded based on the 2006 approved reference plan.

(4) The Province indirectly provides OPG with all of its long-term funding requirements. The Province is the sole shareholder of the Company and is actively involved in the energy-planning process in Ontario and the overall business of the Company. The Province does not directly guarantee OPG or its financial obligations, however DBRS believes the Province will continue to support its investment since it is a creation of the Province and an integral part of meeting the energy needs of Ontarians. OPG on a project-by-project basis enters into negotiated agreements with the Ontario Electric Finance Corporation (OEFC) to finance the project. The Province has provided support to OPG in the past by extending the maturities on OPG's debt held by the OEFC on a number of occasions and by allowing OPG flexibility on dividends. Furthermore, the OEFC is the agency that provides OPG with long-term debt financing.

Challenges

(1) Nuclear generation accounts for approximately 30% of in-service generating capacity and approximately 45% of OPG's 2006 annual production. Nuclear contributions could increase to 59% in 2014 (the scheduled closing of the coal-fired plants) if the Company has not replaced the capacity of the coal-fired plants. Nuclear generation faces higher operating risks than other types of generation due to the complexity of the technology and financial implications of forced outages are greater given the high fixed-cost nature of these plants, as well as the fact that lost revenues resulting from outages are not recoverable through rates. Additionally, nuclear generation carries more regulatory and political uncertainty as a result of the risks associated with the ownership of these plants, such as evolving regulatory rules, safety targets and measures, and costs associated with used fuel-storage and future decommissionings. Furthermore, older nuclear units, such as those at Pickering, are more susceptible to forced outages. For example, in 2005/2006, Pickering A and B have had availability factors in the 70% to 78% range, compared to Darlington, which is newer and has had an average availability of 90%. OPG is undertaking a business case examination on the feasibility of the potential refurbishment and life extension of its Pickering B nuclear station.

(2) (2) A long-term risk facing OPG with respect to its nuclear facilities (as well as those leased to Bruce Power) is uncertainty with respect to the cost of long-term used fuel storage and future decommissioning costs. Under the ONFA, OPG bears the risk and the liability for cost increases and fund earnings in the DF. As at September 30, 2007, the DF is overfunded compared with the estimated completion costs for nuclear fixed-asset removal and the disposal of low- and intermediate-level nuclear waste materials per the most recently approved ONFA reference plan.

(3) The interim regulatory framework governing OPG, while an improvement over the previous pricing mechanisms, is less favourable than frameworks governing regulated electric utilities in many other jurisdictions in North America. OPG's regulated prices are supported by a deemed capital structure of 55% debt/45% equity for the regulated assets and an ROE of 5%. The 5% ROE and revenue cap on unregulated assets penalizes the Company more than other regulated electric utilities in the province. Both regulated transmission and distribution operations in Ontario, which have materially lower business risk profiles, have approved ROEs of 8.35% and 9% respectively. Furthermore, compared to vertically integrated utilities in the United States that have deemed equity components ranging from 35% to 55%, the ROEs are significantly higher, ranging from 9.0% to 13.0%. Additionally, there are generally no provisions under either the regulated or price-capped mechanisms under which operating cost increases (e.g., maintenance, fuel costs) can be recovered.

(4) OPG's fuel-price risk is mostly correlated to its fossil-fuel generation and, to a lesser extent, nuclear. The revenue rate cap currently imposed on fossil-fuelled generation does not account for an abnormal rise in coal prices or an unanticipated increase in coal use. To mitigate this risk, OPG has a fuel-hedging program for all fuel types. For 2007, 2008 and 2009, the Company has hedged 99%, 92% and 75% of its exposure, respectively. Therefore, margins can be constrained if fuel prices rise drastically, especially if the revenue cap is reached or if the volume of coal burned increases unexpectedly (as occurred during the past year).

(5) OPG is subject to political intervention, due largely to changes in government mandates and policies, as well as limits that restrict revenues and earnings should the price of electricity rise quickly. Due to political influence, OPG has been under-earning for a regulated utility. The Company is a creation of and wholly owned by the Province, therefore, it has been subject to various policy changes and interventions. DBRS notes the Province has committed to having OPG run more autonomously, however the risk of further government intervention still exists. The highly contentious policy review that centered on the closing of the coal-fired generating facilities in Ontario is a recent example of political issues that raise uncertainty for the Company and make it more challenging for OPG to undertake long-term strategic planning. In August 2007, the Province finalized a regulation that commits to eliminate the use of coal by December 31, 2014. Furthermore, in June 2007 and April 2007, the Province and Federal governments, respectively, introduced climate-change plans and environmental policies to reduce greenhouse gas emissions.

(6) OPG has a significant capital expenditure program underway and this is likely to increase given the potential new nuclear plants and the refurbishments of existing facilities under consideration. It is expected that OPG will not undertake any major capital projects without having its financing and a cost-recovery mechanism in place, thus minimizing the financial risks. It is also expected that OPG will turn to the OEFC or project-style financing in the capital markets to fund these projects. Although OPG may be able to reduce its risks through design-build contracts, some residual risk will remain on significant capital expenditures.

Ontario Power Generation Inc.

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Regulation

Regulation pursuant to the Electricity Restructuring Act, 2004 (Ontario), allows OPG to receive regulated prices for electricity generated from its nuclear facilities (6,606 MW) and most of its baseload hydroelectric, namely Sir Adam Beck I, II and the Pump Generating Station; DeCew Falls I and II; and R.H. Saunders plant (totalling 3,332 MW), effective April 1, 2005. About 45% of OPG's installed in-service capacity, or 62% of its total generation output, is sold at regulated prices.

The initial regulated prices for electricity generated by OPG's regulated assets are:

- $33/MWh for the first 1,900 MWh in any hour of production from regulated baseload hydroelectric facilities; for production above 1,900 MWh in any hour, it will receive the Ontario electricity spot market price.
- $49.50/MWh for nuclear facilities.

These initial prices are expected to remain in effect until at least March 31, 2008, after which time the OEB will assume responsibility for establishing new regulated prices. Combined, this is expected to result in a weighted-average price of $45/MWh for regulated generation.

These regulated prices were established by the Province, based on a revenue requirement that takes into account a forecast of production volumes and total operating costs, a capital structure of 55% debt/45% equity for the regulated assets and an ROE of 5%.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85% of output from OPG's non-regulated generating facilities (with some exceptions) is subject to a revenue limit that was implemented on January 1, 2005. The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and will increase to 4.8¢/kWh effective May 1, 2008 (compared to the 2007 year-to-date hourly Ontario spot market price (HOEP) of 5.0¢/kWh). In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority (OPA) are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the IESO for the benefit of consumers.

OPG must also maintain variance accounts for costs incurred and revenues earned or foregone on or after April 1, 2005, that are a result of differing amounts from the Province's forecasts that were used to establish the current regulated rates. These variance accounts capture differences that include poor hydrological conditions, changes to regulatory requirements or technological changes, transmission constraints or outages and other events that are beyond OPG's control, such as acts of God. Recovery of items in the variance account will be subject to approval by the OEB. We note that increases in costs, such as fuel expense and maintenance, are generally not included in these variance accounts.

On November 2, 2007, OPG began the pre-submission consultations on its rate application for regulated assets. The Company intends on finalizing the rate application requesting new payment amounts to become effective April 1, 2008, for a 21-month period and submitting it to the OEB at the end of November 2007. The application, if approved, would result in a 14% increase in revenues from these assets and will result in OPG's first rate increase in three years.

Ontario Power Generation Inc.

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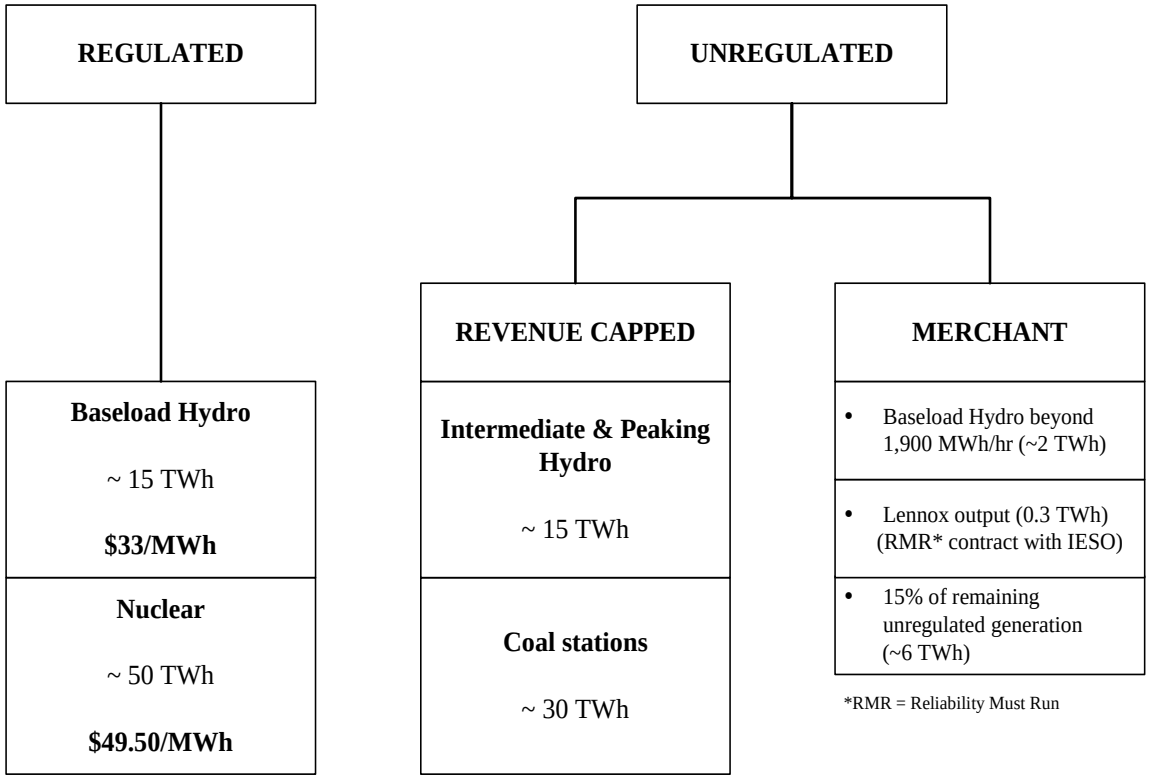
November 30, 2007

OPG's Price Structure



*RMR = Reliability Must Run

- ROE of 5%
- Prices in effect until no earlier than March 31, 2008

85% of production capped (with some exceptions) at
$47/MWh May 1, 2007 to April 30, 2008
$48/MWh beyond May 1, 2008

Ontario Power Generation Inc.

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November 30, 2007

Earnings and Outlook

Income Statement	12 mos ended	For the year ended December 31			
($ millions)	Sept. 30, 2007	2006	2005	2004	2003
Total revenues	5,594	5,564	5,798	4,926	5,178
EBITDA	1,285	1,583	1,878	1,076	993
Depreciation and amortization	658	664	753	765	603
Increase in net nuclear-related liabilities	16	128	95	140	192
EBIT	611	791	1,030	171	198
Gross interest costs	187	214	224	223	219
Net interest costs	150	193	197	189	144
Net income (before extras)	404	504	616	55	(29)
Non-recurring	(14)	(14)	(250)	(13)	(462)
Net income (as reported)	390	490	366	42	(491)
Return on avg. equity (before extras)	6.5%	9.1%	11.8%	1.1%	(0.6%)
EBIT by Segmented (before extras)					
Hydroelectric - Unregulated	349	375	423	n/a	
Fossil-fuel - Unregulated	45	(15)	189	n/a	
Total Unregulated	**394**	**360**	**612**	**228**	
Hydroelectric - Regulated	247	264	375	406	
Nuclear - Regulated	(99)	70	53	(468)	
Total Regulated	**148**	**334**	**428**	**(62)**	
Other *	69	97	(10)	5	
Total EBIT	**611**	**791**	**1,030**	**171**	

Note: With the introduction of rate regulation, reporting definitions of business segments were changed effect April 1, 2005.

* Includes EBIT associated with share of Brighton Beach joint venture, real estate rentals and trading activities. n/a=not available

Summary

Revenues have generally stabilized since the 2005 change to rate regulations that govern the nuclear and baseload hydro facilities.

The revenue reduction from 2005 levels is largely attributable to lower received pricing in 2006 as the revenue limit price was reduced ($0.046 in 2006 versus $0.049 in 2005) and lower wholesale prices on uncapped generation as the HOEP decreased materially from 2005 ($0.049 in 2006 versus $0.072 in 2005); and modestly lowered volumes in 2006 versus 2005 due to lowered demand attributable to less extreme weather in 2006 from 2005 (less heating and cooling degree days).

EBITDA has trended lower since 2005, largely due to reduced revenues (mentioned above), increased fuel costs as coal generation increased to compensate for lower nuclear output and increased OM&A attributable to higher pension and OPEB costs, as well as higher maintenance costs on nuclear and coal facilities. The negative impact on EBITDA of increased operating costs is a function of the pricing mechanics on the regulated and non-regulated but capped pricing assets; under which there is no recovery of increased costs such as fuel and OM&A.

Interest expense decreased on a last 12-months (LTM) basis, due to lower coupon rates and reclassification of interest expense related to Pickering A to a deferral account related to an amendment to regulation.

Outlook

In the near term, EBITDA and earnings should exhibit stability from current levels, although OPG's ability to manage costs will factor into this as cost fluctuations are generally not recoverable under either the regulated or revenue-capped assets. The Company is expected to submit a rate filing with the OEB on the regulated facilities, which OPG has stated would, if approved, result in a 14% rate increase, which would drive some improvement in margins. Additionally, market prices do impact the results on the non-price capped units, as evidenced by the 2005 earnings spike.

Interest expense is expected to increase in the medium term, given the debt financing required to fund the increased capital expenditures, therefore coverage ratios will slightly weaken.

Longer-term earnings growth will be largely driven by capital projects coming into service from both current projects (i.e., the Niagara tunnel) and the large prospective projects under consideration. The closing of the coal-fired units in 2014 should not materially impact EBITDA or earnings as these assets currently do not provide a significant margin due to the revenue caps currently in place.

Financial Profile

	12 mos ended	For the year ended December 31			
($ millions)	Sept. 30, 2007	2006	2005	2004	2003
EBITDA	1,285	1,583	1,878	1,076	993
Net income adj. for non-recurring	404	504	616	55	(29)
Depreciation and amortization	658	664	753	765	603
Incr. in net liab. on decom. & waste fuel mgm't	16	128	95	140	192
Future income taxes	(16)	26	38	(117)	(100)
Recurring non-cash adjustments	203	191	(20)	9	(184)
Cash Flow From Operations	1,265	1,513	1,482	852	482
n.w.f.* and decommissioning	(547)	(599)	(521)	(506)	(525)
Common dividends	(128)	(128)	-	-	(17)
Capital expenditures	(691)	(637)	(494)	(561)	(643)
Free Cash Flow Before Work. Cap. Changes	(101)	149	467	(215)	(703)
Working capital changes	118	316	(147)	(83)	166
Net Free Cash Flow	17	465	320	(298)	(537)
Revenue limit rebate (including MPMA rebate)	(18)	(699)	300	0	0
Other investments & adjustments	(155)	(147)	(179)	(19)	334
Net debt financing	113	(521)	465	33	(135)
Net change in cash and s.t. inv.	(43)	(902)	906	(284)	(338)
EBITDA interest coverage (times)	6.87	7.40	8.38	4.83	4.53
Fixed-charges coverage (times)	3.27	3.70	4.60	0.78	1.00
Senior debt-to-capital [(1)]	28.4%	31.0%	36.0%	34.1%	34.0%
Total debt-to-capital [(2)]	35.6%	31.0%	36.0%	42.6%	42.6%
Net total debt-to-capital [(3)]	34.8%	39.0%	37.9%	42.6%	40.7%
(Cash flow - n.w.f.*) / CAPEX	1.04	1.43	1.94	0.62	(0.07)
(Cash flow - n.w.f.*) / Total debt	19.4%	24.9%	22.9%	9.3%	(1.2%)

(1) Senior debt = Senior debt held by the OEFC + Bank debt + A/R securitization (2) Total debt = Senior debt + Subordinated debt held by the OEFC.

(3) Net debt-to-capital = (Total debt - Cash) / (Total capital - Cash).

* n.w.f. = nuclear waste funding. This is subtracted from cash flow because the payments are not discretionary.

Note: Debt ratios include receivable sales as a debt equivalent.

Summary

Cash flow from operations has largely tracked EBITDA trends, with recent lower revenues and non-recoverable cost increases reducing cash flow. However, a marked improvement is evident since the imposition of regulated pricing in early 2005. Capital expenditures have ranged from $500MM to $700MM since 2003, with recent levels above the 2005 low point, due to increased spending on initiatives including the Portlands Energy Centre, investments in coal and nuclear facilities, and the Niagara Tunnel project. Funding for nuclear fuel waste and decommissioning, however, has remained reasonably steady.

Dividends to the Province were reinstituted in 2006 with a $128 million payment, the first dividend paid since 2003.

Operating cash flow in 2005 and 2006 was sufficient to cover nuclear waste fuel and decommissioning expenses, as well as capital expenditures and common dividends; although a small deficit (before working capital) was recorded on an LTM basis. Again, this represents a large improvement over pre-2005 levels.

While debt levels have fluctuated modestly year-over-year, they have been essentially flat since 2003. So, as a result, key credit metrics (debt/capital, EBITDA/interest and cash flow/debt) have all improved since 2004. The modest debt swings in 2005 and 2006 were driven by the timing of remittances under the revenue limit and MPMA payments.

Outlook

In the near term, operating cash flows are expected to be reasonably stable, compared with current levels, and should be sufficient to fund maintenance, capital expenditures and nuclear-waste fuel and decommissioning expenses. However, given the growth/enhancement projects currently under construction (Niagara tunnel, Portlands etc.), and a large expected nuclear-funds cash contribution, we would anticipate free cash flow deficits to be incurred. Note this does not assume the undertaking on any of as-yet uncommitted capital projects (Pickering B refurbishment, Darlington new unit construction, etc.).

Capital expenditures are expected to average $700 million in each of 2008 and 2009 (excluding the additional costs of any new projects), resulting in modest free cash flow deficits that would be funded with a modest increase in debt. As debt is added to fund capital expenditures, credit metrics would be expected to decline from current levels, as assets do not generate earnings or cash flows until placed in service. Once in service, metrics would be expected to improve.

Longer term, cash flow will be driven by prices received on the regulated and price-capped units, and incremental cash flow generated from new assets. The inclusion of any of the material capital projects currently under consideration would be the key drivers of cash flow deficits. DBRS would expect the Province to forgo dividends at a time of increased capital expenditures.

Ontario Power Generation Inc.

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Long-Term Debt Maturities and Credit Facilities

Long-term Debt September 30, 2007 (CAD millions)	**2007**	**2008**	**2009**	**2010**	**2011 & Thereafter**	**Total**
OEFC Senior debt	200	400	350	595	920	2,465
OEFC Subordinated debt	-	-	-	375	375	750
Brighton Beach project debt	-	-	-	-	189	189
Total	200	400	350	970	1,484	3,404

Credit Facilities as at Sept. 30, 2007 (CAD millions)

Bank facilities	**Maturity**	**Amount**	**Outstanding**	**Available**
Committed credit facility - Tranche 1	May 21, 2008	500	0	500
Committed credit facility - Tranche 2	May 22, 2012	500	0	500
Short-term uncommitted credit facilities	No Maturity	238	201	37
Short-term uncommitted overdraft facilities	No Maturity	25	0	25
Total		1,263	201	1,062
OEFC facilities				
Niagara Tunnel project facility	Nov. 30, 2010	1,000	240	760
Portlands Energy Centre project facility	Dec. 31, 2009	400	160	240
Lac Seul project facility	Dec. 31, 2009	50	20	30
General corporate facility	Mar. 31, 2008	500	100	400
Credit facility	Sept. 22, 2009	950	200	750
Total		2,900	720	2,180

The OEFC provides OPG with its long-term debt financing on a project-by-project basis. OPG currently has a total of $1,450 million of project facilities with $420 million drawn as of September 30, 2007, for the Niagara Tunnel, Portlands Energy Centre and Lac Seul projects under construction. It is expected that OPG will not undertake any major capital projects without being assured of financing and an in-place cost-recovery mechanism, thus minimizing the financial risks.

The current debt maturity profile is shorter than comparable entities, considering the remaining asset life. This necessitates continued financial support from the Province to refinance OEFC debt maturities. Currently, the OEFC provides credit facilities totaling $1,450 million that consist of a $500 million general corporate facility maturing March 31, 2008, and a $950 million refinancing credit facility maturing September 22, 2009. The OEFC agreed to provide OPG with these facilities to restructure the existing OEFC debt that matures from June 2007 to September 2010. The refinanced debt has a maximum term of ten years at fixed rates, which will extend the Company's debt maturity profile.

OPG's liquidity is adequate for the rating category. The Company has a $1 billion syndicated bank credit facility that backs its $1 billion commercial paper program. This facility is comprised of a 364-day, $500 million tranche maturing in 2008 and a five-year $500 million tranche maturing in 2012. No commercial paper was outstanding as at September 30, 2007.

OPG has $215 million of short-term uncommitted credit facilities that are used to support Letters of Credit and a $25 million short-term uncommitted overdraft facility. At September 30, 2007, a total of $201 million of Letters of Credit were issued.

OPG's liquidity is also supported by its securitization agreement (maturing August 2009) with an independent trust to sell receivables up to a maximum of $300 million. As at September 30, 2007, the maximum $300 million was outstanding.

At September 30, 2007, OPG's holdings of asset-backed commercial paper was $103 million, of which the Company expects $45 million will be recovered in late 2007. This level of exposure is not viewed as a material credit concern for OPG given its sizeable liquidity position.

Capital Expenditure Outlook

Significant Projects	Fuel Source	Budgeted Cost (CAD millions)	CAPEX Spent As of Sept. 30, 2007 (CAD millions)	CAPEX Remaining As of Sept. 30, 2007 (CAD millions)	Additional Capacity (MW)	Forecasted Completion
Under Construction						
Niagara Tunnel	Hydro	985	281	704	1,600	Late 2009 to mid 2010
Portlands Energy Centre 50/50 Joint Venture	Cogen.	400*	244*	156*	550**	Q2 2009
Lac Seul	Hydro	47	38	9	13	Q2 2008

* Figures reflect OPG's 50% share of the cost in the joint venture **This capacity is the total for the facility

Capital expenditures for the year ended 2007 are expected to be approximately $700 million to $1 billion, including amounts for the Niagara Tunnel project, Portlands Energy Centre and Lac Seul project.

OPG manages its construction risk by contracting with third parties for the construction of the projects, thereby transfering some of the construction cost over-runs, schedule-adherence and other construct-related risks to the contractor.

The Niagara Tunnel project is expected to increase annual generation capacity of the Sir Adam Beck generating stations in Niagara Falls by approximately 1,600 MW. The completion date for the Niagara Tunnel project is still expected to be mid-2010, despite slower progress by the tunnel-boring machine. It is anticipated that the project will be completed within the budget estimate and it is being debt financed through the OEFC.

OPG is currently jointly developing the Portlands Energy Centre cogeneration facility with TransCanada Energy Ltd. OPG will proportionately consolidate their 50-per-cent interest in the 550 MW joint venture. The project remains on schedule; single-cycle operation is expected to be on line by June 2008 and combined cycle by Q2 2009. OPG's $400 million share of the cost is being debt financed through the OEFC.

OPG's capital program is expected to remain significant over the medium to longer term, due to the large number of projects in OPG's concept/development pipeline, most notably a potential refurbishment of Pickering B, new nuclear units Darlington, the Upper/Lower Mattagami hydro development and a possible re-powering of the Lakeview site.

Ontario Power Generation Inc.

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Company Profile

Generation Portfolio

	Per Cent	Capacity (MW)	Plant Availability 9 mos Sept/07	Year ended 2006	2005	2004
Nuclear						
Darlington	*16%*	3,512	91%	89%	91%	88%
Pickering A	*5%*	1,030	42%	72%	70%	76%
Pickering B	*9%*	2,064	75%	75%	78%	70%
	30%	6,606				
Fossil-Fuel (1)						
Nanticoke (Coal)	*18%*	3,933				
Lambton (Coal)	*9%*	1,975				
Atikokan (Coal)	*1%*	215				
Thunder Bay (Coal)	*1%*	310				
Lennox (Duel oil & gas)	*10%*	2,140				
	39%	8,573	89%	86%	84%	81%
Hydroelectric						
Non-regulated (1)(2)	*16%*	3,639	94%	98%	99%	99%
Regulated (1)(2)	*15%*	3,332	94%	99%	99%	98%
	31%	6,971				
Huron & Pickering (Wind)	*0%*	7				
Total Capacity	*100%*	22,157				

(1) Fossil fuel and Hydroelectric plant availability is measured by equivalent forced outage rate by business segment

(2) Total hydroelectric portfolio comprises 64 stations.

Ontario Power Generation is responsible for approximately 71% of the electricity generation in the Province. As of December 31, 2006, OPG had a total in-service capacity of 22,147 megawatts (MW) and generated 105.2 terawatt hours (TWh) of electricity during the year. OPG's electricity-generating portfolio consists of the following:

- Three nuclear generating stations (Pickering A, Pickering B and Darlington), with a capacity of 6,606 MW.
- Five fossil-fuelled generating stations with a capacity of 8,578 MW.
- 64 hydroelectric generating stations with a capacity of 6,956 MW.
- Three wind-generating stations (which includes a 50% interest in the Huron Wind joint venture) with a capacity of 7 MW.

OPG partnerships consist of:

- OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach Generating Station, a 580 MW natural gas-fired generating station.
- OPG jointly owns with TransCanada Energy, the Portlands Energy Centre, a 550 MW natural gas-fired generating station that is currently under construction.
- OPG also owns two other nuclear generating stations, Bruce A and Bruce B, which are leased on a long-term basis to Bruce Power L.P.

Ontario Power Generation Inc.

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Ontario Power Generation Inc.

Balance Sheet	As at	As at December 31			As at	As at December 31	
($ millions)	Sept. 30, 2007	2006	2005		Sept. 30, 2007	2006	2005
Cash + short-term investments	235	6	908	Debt due one year	406	421	806
Accounts receivable	230	256	538	A/P + accr'ds + other	1,019	1,132	1,051
Future income taxes	-	-	18	MPMA rebate	67	40	739
Fuel	508	669	581	**Current Liabilities**	1,492	1,593	2,596
Material & supplies	178	112	115	Long-term debt	2,248	2,203	2,339
Current Assets	1,151	1,043	2,160	Subordinate l.t. debt	750	750	750
Net fixed assets	12,761	12,761	11,412	Waste mgmt. liab.	10,857	10,520	8,759
Defined pension assets	722	706	663	Other liabilities	589	539	580
Regulatory & other assets	791	646	600	Post-employ. benefits	1,529	1,396	1,212
Nuclear waste management fund	8,743	7,594	6,788	Equity	6,703	5,749	5,387
Total	24,168	22,750	21,623	**Total**	24,168	22,750	21,623

	12 months ended	For the year ended December 31			
Liquidity & Cash Flow Ratios	Sept. 30, 2007	2006	2005	2004	2003
Current ratio	0.77	0.65	0.83	0.73	0.87
Cash flow / CAPEX	1.83	2.38	3.00	1.52	0.75
(Cash flow - n.w.f.*) / CAPEX	1.04	1.43	1.94	0.62	(0.07)
(Cash flow - n.w.f.* - Dividends) / CAPEX	0.85	1.23	1.94	0.62	(0.09)
(Cash flow - n.w.f.*) / Total debt	19.4%	24.9%	22.9%	9.3%	(1.2%)
Leverage Ratios					
Senior debt-to-capital (1)	28.4%	31.0%	36.0%	34.1%	34.0%
Total debt-to-capital (2)	35.6%	39.0%	43.8%	42.6%	42.6%
Net debt-to-capital (3)	34.8%	39.0%	37.9%	42.6%	40.7%
Total gross debt / EBITDA	2.88	2.32	2.23	3.47	3.72
Coverage Ratios (4)					
EBIT interest coverage	3.27	3.70	4.60	0.77	0.90
Fixed-charges coverage	3.27	3.70	4.60	0.78	1.00
EBITDA interest coverage	6.87	7.40	8.38	4.83	4.53
Earnings Quality & Operating Efficiency					
Fuel costs / Revenues	22.0%	19.7%	22.4%	23.4%	32.4%
EBIT margin	10.9%	14.2%	17.8%	3.5%	3.8%
Net margin (before extras)	7.2%	9.1%	10.6%	1.1%	(0.6%)
Return on average equity (before extras)	6.5%	9.1%	11.8%	1.1%	(0.6%)
Profit returned to gov't (before extras)	49.9%	46.6%	34.5%	35.6%	127.4%
Common dividend payout (before extras)	31.7%	25.4%	0.0%	0.0%	(58.6%)

* n.w.f. = nuclear waste funding. This is subtracted from cash flow because the payments are not discretionary.

(1) Senior debt = Senior debt held by the OEFC + bank debt + securitization of receivables.

(2) Total debt = Senior debt held by the OEFC + bank debt + securitization of receivables + subordinated debt held by the OEFC.

(3) Net debt-to-capital = (Gross debt - cash) / (Total capitalization - cash).

(4) EBIT includes interest income. Interest expense before capitalized interest, AFUDC and debt amortizations.

Ontario Power Generation Inc.

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Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debt*	A (low)	Confirmed	Stable

* Debt held by the Ontario Electric Finance Corporation.

Rating History

	Current	2006	2005	2004	2003	2002
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A

Related Research

- Comments on ABCP Exposure, August 28, 2007
- Ontario Power Generation Inc., August 3, 2006
- Comments on New Electricity Pricing, February 23, 2005

Note:
All figures are in Canadian dollars, unless otherwise noted.

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Insight beyond the rating.

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Toronto Hydro Corporation

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper/Short-Term Obligations
A	Stable	Confirmed	Senior Unsecured Debentures & MTNs

RATING HISTORY	Current	2006	2005	2004	2003	2002
Commercial Paper/Short-Term Obligations	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures & MTNs	A	A	A	A (low)	A (low)	A

RATING UPDATE

DBRS has confirmed the ratings of Toronto Hydro Corporation (Toronto Hydro or the Company) as follows: Senior Unsecured Debentures & MTNs at "A" and Commercial Paper/Short-Term Obligations at R-1 (low), both with Stable trends. The ratings confirmation reflects Toronto Hydro's low business risk profile, accompanied by the continuation of a solid financial profile, which is supported by a strong balance sheet, good credit metrics and a modestly improving regulatory environment in Ontario, which underpins the current ratings.

The regulatory environment in Ontario continues to modestly improve, despite the April 2006 decision of the Ontario Energy Board (OEB) that established an overall lower return on equity (ROE) for Toronto Hydro's regulated subsidiary and reduced allowable interest rate recoverable on related party debt, namely, the outstanding $980 million promissory note between Toronto Hydro-Electric System Limited (THESL) and the Company from 6.8% to 5.0% per annum. (Continued on page 2.)

RATING CONSIDERATIONS

Strengths:

- Regulated electricity distribution has low business risk and provides long-term stability to earnings and cash flows
- Strong franchise area
- Solid credit metrics/balance sheet
- Strong reliability measures/operational efficiency
- Expiration of competitive electricity contracts and the divestiture of non-regulated operations

Challenges:

- Significant upcoming capital investment program
- Approved ROE sensitive to long-term interest rates
- Earnings sensitive to volume of electricity sold
- Unable to access equity capital markets
- Significant external financing required

FINANCIAL INFORMATION

	12 mos ended	For the year ended December 31			
	Mar. 2007	2006	2005	2004	2003
Total debt (CAD millions) (1)	1,216	1,216	1,216	1,215	1,215
Total debt-to-capital (%) (1)	57.4%	57.7%	59.0%	59.7%	61.2%
Net debt -to-capital (%) (1)	40.5%	42.1%	37.2%	40.7%	46.2%
Cash flow/total debt (%) (1)	16.4%	17.9%	16.6%	17.4%	20.9%
Cash flow/capital expenditures (times)	1.08	1.18	1.44	1.93	2.27
EBIT coverage (times) (1)	2.21	2.39	2.27	2.25	2.94
Operating cash flow (CAD millions)	198.8	217.9	201.6	211.6	254.3
Core net income (CAD millions)*	68	77	64	64	102
Reported net income (CAD millions)	107	92	92	97	98
Return on average equity	7.7%	8.9%	7.7%	8.0%	14.2%
Electricity throughputs (million kWh)	na	25,527	26,372	25,636	25,733

*DBRS adjusted to exclude mark-to-market in revenues. (1) DBRS adjusted for operating lease equivalents.

THE COMPANY

Toronto Hydro Corporation is a holding company with the following subsidiaries: Toronto Hydro-Electric System Ltd. (THESL), which distributes electricity; Toronto Hydro Energy Services Inc. (Energy Services), which provides street lighting and expressway lighting services and energy-efficient products and services; and Toronto Hydro Telecom Inc., which provides fibre-optic capacity and manages data communication services. Toronto Hydro's sole shareholder is the City of Toronto (the City), rated AA by DBRS.

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RATING UPDATE (Continued from page 1.)

The OEB decision had a modest impact on the Company's earnings and key coverage ratios. As such, Toronto Hydro will repay the promissory note over a seven-year period in four $245 million tranches, which places significant dependence on external financing requirements. Maintaining adequate access to the debt markets is critical during this refinancing schedule.

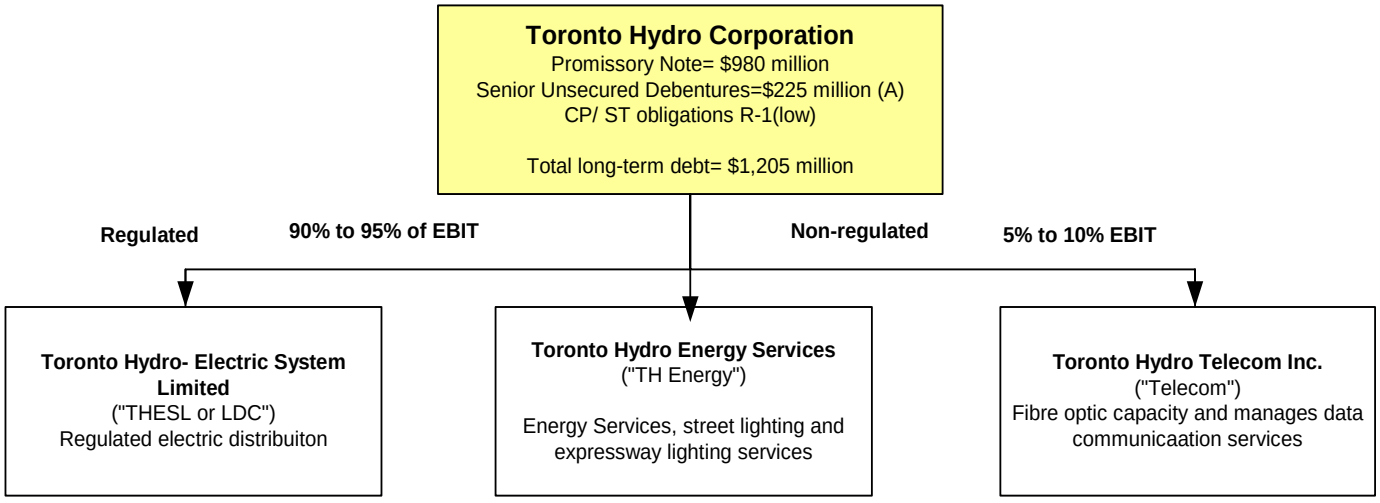
Furthermore, on the regulatory front, the OEB's new regulatory framework under the 2nd Generation Incentive Regulation Model (IRM) and Cost of Capital is viewed by DBRS as reasonable, but largely credit neutral for Toronto Hydro, providing sufficient earnings and cash flow stability. In 2008, DBRS expects THESL to file a three-year rate application (2008 to 2010) encompassing, among other things, a ten-year capital plan and a workforce renewal strategy.

Toronto Hydro is entering a significant capital investment program to modernize its distribution system. Recently, THESL completed a ten year modernization assessment for the distribution system and filed a capital plan of $1.2 billion with the OEB for distribution assets. This capital plan focuses on the modernization of THESL's distribution system. DBRS expects capital investment in the range of $275 million to $300 million per annum, a 55% to 60% increase from 2006 capital expenditure levels, which is projected to result in manageable free cash flow deficits over the medium term. As such, moderate external financing is required during this build-out phase, in which the regulatory environment plays a paramount role in ensuring a predictable and stable environment for investment.

DBRS anticipates earnings and operating cash flow to remain under pressure over the near term, from lower regulated returns, limited earnings contribution from non-regulated operations and increased capital expenditures; however, leverage and coverage ratios are expected to remain within ranges consistent with the assigned ratings. Over the longer term, earnings growth should trend higher reflecting the following: (1) the equity thickness of the capital structure increasing from 35% to 40% over a two-year period beginning on May 1, 2008; (2) THESL's revenue requirement is re-based in 2008; and (3) THESL continues strong reliability measures and prudent cost management.

DBRS believes that over the medium term, the Company's operations will remain relatively stable going forward, barring any unexpected regulatory or political decisions.

CORPORATE STRUCTURE



RATING CONSIDERATIONS

Strengths

(1) Toronto Hydro is predominately a regulated electric distribution company that operates in a modestly improving regulatory environment. DBRS expects THESL to file a three-year cost-of-service rate application (2008 to 2010) encompassing, among other things, a ten-year capital plan and a workforce renewal strategy. DBRS views the new regulatory framework under the 2nd Generation IRM and Cost of Capital decision as reasonable, providing sufficient earnings and cash flow stability. DBRS believes

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the OEB will be supportive in the recovery of capital costs.
(2) Toronto Hydro is one of the largest municipally owned local distribution companies (LDCs) in Canada, serving a large customer base (678,000 customers) in a strong franchise area. More than 95% of Toronto Hydro's electricity sales are to residential and general service customers, which have relatively stable demand year over year, as these customers are less sensitive to economic cycles.
(3) Toronto Hydro's credit metrics remain solid for a utility that benefits from low business risk and are consistent with current ratings: debt-to-capital ratio at 57.4%, EBIT interest coverage at 2.21 times and cash flow-to-debt at 16.4% (12 months ended March 2007). Although DBRS expects coverage ratios to experience modest downward pressure given the higher capital expenditures driving manageable free cash flow deficits, financial metrics are expected to remain within a range that is reasonable for the assigned rating.
(4) THESL continues to exceed OEB service level targets, which should provide a better platform to facilitate a constructive relationship with the regulators.
(5) Toronto Hydro's business risk profile has improved gradually over the years as higher-risk, non-regulated operations have continued to represent a decreasing proportion of consolidated operations. Toronto Hydro is focused on its core regulated utility business, which will account for approximately 95% of consolidated EBIT, providing for a predictable and stable earnings profile going forward.

Challenges
(1) The Company is entering a build-out program to enhance the reliability of the system and replace aging assets. The Company has filed a capital plan of $1.2 billion with the OEB for distribution assets. Going forward, DBRS expects capital investment in the range of $275 million to $300 million per annum through 2011, which, combined with dividends, is expected to exceed operating cash flows by approximately $100 to $150 million per year. The manageable free cash flow deficits are expected to place modest pressure on the balance sheet and coverage ratios.
(2) Regulatory-allowed ROE levels are low and could continue to decline if the longer-term interest rates decline. The ROE of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower ROE is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009.
(3) Earnings and cash flows for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather variability directly impact the volume of electricity sold, and hence, revenue earned from electricity sales.
(4) Due to municipal ownership, Toronto Hydro does not have access to the equity capital markets. This limits the Company's financial flexibility, as free cash flow deficits will likely be financed with cash on the balance sheet ($358 million at March 31, 2007) or debt issuance. However, the dividend payout with the City is reasonable and modestly lower than the majority of municipally owned utilities across Canada.
(5) The Company is dependent upon the debt markets to refinance the $980 million City promissory note and fund capital investments in THESL. Over the next seven years, Toronto Hydro will have to refinance 100% ($1,205 million) of its outstanding debt, exposing the company to interest rate risk. Maintaining adequate access to the debt markets is critical during this refinancing and build-out phase. DBRS believes the following factors should help facilitate Toronto Hydro's access to the debt markets: (a) reduced uncertainty associated with the regulatory environment and (b) low business risk profile accompanied by a strong financial profile. Refinancing the debt could expose the Company to some upside interest rate risk given the current inflationary environment and the modestly upward sloping yield curve. However, because much of this debt was incurred for THESL, a market-based interest rate on third-party debt should be fully recoverable from ratepayers. Furthermore, DBRS believes the Company will go to the market with longer-dated debentures and spread out the maturities in an effort to match debt obligations with its average asset life and lessen the refinancing of a high percentage of outstanding debt during a short period of time.

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REGULATION

Toronto Hydro's electricity distribution operations are regulated by the Ontario Energy Board (OEB) under the *Electricity Act, 1998* (the Electricity Act), as modified by the following noteworthy amendments:

- The *Electricity Pricing, Conservation and Supply Act, 2002* (Bill 210) – December 9, 2002;
- The O*ntario Energy Board Amendment Act, 2003* (Bill 4) – December 18, 2003; and
- The *Electricity Restructuring Act, 2004* (Bill 100) – December 9, 2004.

Currently, THESL operates under cost-of-service regulation with a deemed ROE of 9.0%.

In April 2006, the OEB decreased Toronto Hydro's distribution rates for the May 1, 2006, to April 30, 2007, period, representing a revenue reduction of approximately $58 million. The methodology used by the OEB to establish the distribution rates was based on a rate base of $1.861 billion, a deemed debt-to-equity structure of 65-to-35 and an allowed ROE of 9.0%. Furthermore, the OEB reduced allowable interest rate recoverable on related party debt to 5.0% from 6.80%, which impacted Company's earnings, cash flows and coverage ratios.

On December 20, 2006, the OEB issued a 2007 rate adjustment model (2nd Generation Incentive Regulation Model and Cost of Capital) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. As a result, base distribution rates, exclusive of rate riders, were adjusted formulaically to reflect an allowance for inflation, a fixed productivity offset of 1.0%, and removal of the federal large corporation tax. As such, no major financial impact for distributors, only a marginal increase in revenues, is expected due to the inflation factor generally being slightly higher than the productivity factor. In each of three subsequent years, approximately one-third of the electricity distributors will have their distribution rates reviewed and reset by the OEB through a cost-of-service type of rate proceeding. LDCs re-based in 2008 will be subject to an Incentive Rate Mechanism applied in succeeding years up to the 2010 rate year. By 2010, all electricity distributors in Ontario will have undergone a re-basing of rates. The net effect of the OEB decision in 2007 was to provide for approximately a 0.9% increase in base distribution rates to all customer classes for the May 1, 2007 to April 30, 2008 period.

On March 27, 2007, the OEB advised THESL regarding the March 21, 2007, rate application that it would consider the smart meter deferral account (approximately $36 million to the end of 2006) and the adjustment to rate base in a "combined" proceeding that will commence after May 1, 2007. In addition, the OEB agreed to proceed with a hearing for THESL's recovery of costs for lost revenue and utility incentives due to the successful conservation programs in 2005 and 2006 (approximately $10.4 million). Hearings into both these matters were held over the June–July 2007 period and have now concluded. THESL expects that a decision into these matters will be released by the OEB in time for rate adjustments to be made on November 1, 2007.

EARNINGS AND OUTLOOK

	12 mos ended	For the year ended December 31			
(CAD millions)	Mar. 2007	2006	2005	2004	2003
Net operating revenues *	513.8	520.5	512.2	509.7	555.0
Operating costs	344.2	331.6	322.8	320.8	317.9
EBITDA*	309.2	326.3	321.0	323.7	371.1
EBIT*	169.7	188.9	189.4	188.9	242.1
Gross interest expense	76.5	78.8	83.1	83.8	81.9
Payments in lieu of income taxes	43.1	50.9	56.4	53.5	69.9
Core net income*	67.7	76.9	64.0	63.9	101.9
Reported net income	107.5	92.4	92.4	97.3	98.4
Return on equity	8%	9%	8%	8%	14%
Operating margin	33%	36%	37%	37%	44%
Reported regulated EBIT	na	187	194	174	176
Reported non-regulated EBIT	na	23	30	65	57
% of EBIT non-regulated	na	11%	13%	27%	25%

*DBRS adjusted to exclude mark-to-market in revenues.

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Summary

- Earnings, as measured by EBIT, declined modestly for the 12 months ended March 2007, largely reflecting the related party interest decision and increased operating expenses. Furthermore, the decline in EBIT is partially a result of the sale of its water heater business to Consumer's Waterheater Income Fund for cash consideration of $40.8 million, subject to closing adjustments and transaction costs. The results of the water heater operations and financial position have been reflected as discontinued operations.
- DBRS notes the recent upswing in operating costs was primarily driven by the increased employee head count as Toronto Hydro integrates a new workforce to replace the existing demographic of pension-eligible employees.
- Interest rate expense decreased moderately reflecting the amended promissory note between the Company and the City, which represented a 69 basis point decrease (approximately $6.7 million) from the 6.80% to 6.11%.
- The following factors continue to impact earnings:
  - Regulatory-approved ROE levels, which are tied to Canadian long-term bond yields.
  - Regulatory approvals for increases in the rate base, in line with capital expenditures, which will be added to the rate base at the completion of system upgrades.
  - Operating efficiency, to outperform the 1.0% productivity factor.
  - Significantly lower earnings contribution from non-regulated businesses.
  - Weather conditions directly impact the volume of electricity sold and revenues earned.
  - OEB decision to amend the deemed interest rate on the Company's debt component, creating a 111 basis point spread on $980 million outstanding debt that will not be recovered through distribution rates.
- Net income has generally tracked EBIT; however, it did not in 2007 due to the sale of the water heater operations.

Outlook

EBIT will continue to be pressured over the near term as lower regulated returns and limited earnings contribution from non-regulated operations pressure earnings. However, earnings should register moderate growth beyond 2008, reflecting the following:

- DBRS expects THESL to file a three-year cost-of-service rate application (2008 to 2010) encompassing a capital plan and a facilities application.
- Equity component of capital structure to increase to 40% in 2010 from 35% in 2007.
- OEB will address the recovery of smart meter costs (approximately $36 million to the end of 2006) and lost revenue from successful execution of Conservation Demand Management programs ($10.4 million) over the next three to four months.
- The rate base will reflect the significant increase in capital expenditures over the next few years.
- The OEB's decision to reduce the allowable interest rate recoverable on related party debt

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will continue to have an impact on earnings of approximately $10 million per year. This negative impact should be negated over time as related party debt is refinanced with third party debt.

- The Company's regulated electricity distribution business will continue to provide a high degree of stability to earnings and cash flows over the longer term.

FINANCIAL PROFILE AND OUTLOOK

Cash-Flow Statement	12 mos ended	For the year ended December 31			
(CAD millions)	Mar. 2007	2006	2005	2004	2003
Net income (before non-recurring)	68	77	64	64	102
Depreciation and amortization	140	137	132	135	129
Other non-cash adjustments	(9)	4	6	13	23
Cash Flow From Operations *	**199**	**218**	**202**	**212**	**254**
Dividends paid	(46)	(46)	(68)	(49)	(5)
Capital expenditures	(185)	(185)	(140)	(110)	(112)
Gross Free Cash Flow	**(32)**	**(14)**	**(7)**	**53**	**137**
Changes in working capital	(43)	(145)	100	2	112
Net Free Cash Flow	**(75)**	**(158)**	**94**	**54**	**250**
Acquistions	0	0	(60)	0	0
Dispositions	42	1	5	5	1
Change in regulatory assets (increase)/ decrease	17	(4)	21	15	(4)
Non-recurring / Other	39	40	23	10	(0)
Cash Flow before Financing	**23**	**(122)**	**82**	**85**	**247**
Net debt financing	0	0	0	0	9
Customer deposits / repayment of capital lease	(1)	1	(22)	4	6
Net Change in Cash	**23**	**(121)**	**62**	**89**	**265**

Key Financial Ratios					
Total debt in capital structure (1)	1,215.6	1,215.6	1,216.0	1,214.7	1,214.7
Total debt-to-captial (1)	57.4%	57.7%	59.0%	59.7%	61.2%
Cash flow/total debt (1)	16.4%	17.9%	16.6%	17.4%	20.9%
EBITDA coverage (times) (1)	4.01	4.11	3.83	3.84	4.50
EBIT coverage (times) (1)	2.21	2.39	2.27	2.25	2.94
Dividend payout	68%	60%	106%	77%	5%

*Operating cash flow adjusted to exclude mark-to-market in revenues. (1)DBRS adjusted for operating lease equivalents

Summary

- Operating cash flow has remained reasonably stable, with the recent modest decline largely tracking EBIT.
- The recent upward trend in capital expenditures, combined with dividends (set at the greater of $25 million or 50% of net income), has resulted in very modest free cash flow deficits.
- The large swings in working capital are mainly due to the timing of the Company receiving and paying a customer rebate (pass-through of the commodity cost of electricity) from the Independent Electricity System Operator (IESO).
- In February 2007, the Company sold its water heater assets to Consumers' Waterheater Income Fund for approximately $40.8 million. This is in line with the Company's focus on its electric distribution business.
- Key credit metrics have remained relatively stable from 2004 levels, as debt levels have been constant with a growing equity base and lower interest expense on the Company's promissory note, and remain solidly within the current rating category for a low-risk distribution utility with debt-to-capital at 57.4%, EBIT interest coverage at 2.21 times and cash flow-to-debt at 16.4%.

Outlook

- Operating cash flows will experience moderate downward pressure as earnings contribution from non-regulated segment declines, partially offset by higher depreciation trending in line with higher capital expenditures.
- With Toronto Hydro entering a significant capital build-out program, DBRS expects:

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- Annual capital expenditures will average approximately $275 million to $300 million from 2007 to 2011, due to the capital plan of $1.3 billion filed with the OEB for the modernization of the distribution system.
- The current dividend policy will increase liquidity needs due to the formula approach over the medium term as the Company is committed to investing heavily in the distribution system.
- As such, DBRS expects the Company will incur manageable levels of free cash flow deficits (in the range, on average, of $100 million to $150 million per year), which will be financed through debt issuances and current cash on the balance sheet ($357 million).

- Toronto Hydro is expected to file a three-year cost-of-service rate application (2008 to 2010) that will encompass, among other things, a capital plan and a workforce renewal strategy. This should improve operating cash flow as the invested capital is added to the rate base, thereby increasing the earnings profile.
- Toronto Hydro's remaining non-regulated operations are relatively low-risk and are expected to generate reasonable cash flows.
- The Company's leverage is not expected to exceed 60% as a growing equity base should largely offset incremental debt levels. Cash flow-to-debt and interest coverage ratios are expected to experience modest pressure until new assets enter rate base, but they should remain within the range of the current assigned ratings for a regulated distribution utility.

LONG-TERM DEBT MATURITIES AND BANK LINES

Repayment schedule	%	$ millions
2007	20%	245
2008	0%	0
2009	20%	245
2010	0%	0
2011	20%	245
2012	0%	0
2013	39%	470
Total		**1,205**

Credit Facility ($ millions)	Amount	LC's	Available	Expiry
Three year revolving credit facility	500	80	420	5/4/2008

Long-term debt	Int. rate	$ millions	Maturity
Senior Unsecured debentures	6.1%	225	5/7/2013
Promissory note payable to the City	6.1%	980	2007 to 2013
Total debt		**1,205**	

Long-Term Debt

- Toronto Hydro has long-term debt (senior unsecured and promissory notes, $1,205 million outstanding at March 2007) and a three-year revolving credit facility ($500 million).
  - The debt-repayment schedule is considerable over the next seven years, as Toronto Hydro will have to refinance 100% of its outstanding debt. Refinancing the debt could expose the Company to some interest rate risk. DBRS believes the Company can mitigate future refinancing risk by issuing longer dated debentures with spread-out maturities to better match debt obligations with asset lives.
- DBRS believes refinancing the promissory note is within Toronto Hydro's financing capacity given its strong financial profile and modestly improving regulatory environment.
- In January 2006, the Company filed a short-form base shelf prospectus allowing it to issue up to $1 billion of senior unsecured debentures.
- The debenture indenture includes the following covenants:
  - Any additional indebtedness is subject to a 75% capitalization ratio test
  - Negative pledge clause.
  - Limitations on designated subsidiary indebtedness.
- The $980.2 million promissory note with the City of Toronto ranks pari passu with the Senior Unsecured Debentures.

Liquidity

- Liquidity requirements will increase over the medium term to accommodate higher capital expenditures and regulatory working capital needs, estimated at $300 million. DBRS notes that Toronto Hydro has reasonable liquidity, with $420 million unused capacity under the Company's $500 million credit line at the end of March 31, 2007.
- DBRS notes that Toronto Hydro currently does not have a commercial paper program.

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Toronto Hydro Corporation

Balance Sheet

(CAD millions)	12 mos ended	As at December 31			12 mos ended	As at December 31	
Assets	Mar. 2007	2006	2005	**Liabilities and Equity**	Mar. 2007	2006	2005
Cash + short-term investments	357.8	327.5	448.4	Short-term debt	245.1	245.1	330.0
A/R + unbilled revenue	419.0	435.3	445.9	A/P + accruals	277.1	285.2	423.8
Inventories	25.5	22.5	18.2	Elec. mark-to-market	0.0	0.0	86.9
Electricity mark-to-market	0.0	0.0	113.3	Other current liab.	25.4	24.9	100.6
Prepaids and other	4.0	15.2	35.4	**Current Liabilities**	547.6	555.1	941.2
Current Assets	806.3	800.5	1,061.1	Customer deposits	19.7	25.9	2.9
Net fixed assets	1,665.4	1,656.9	1,624.7	Long-term debt	960.2	960.2	875.2
Future income tax asset	15.9	16.0	22.3	Employment benefits	136.8	134.7	125.4
Regulatory assets	70.8	66.5	63.8	Other liabilities	42.1	23.7	28.6
Intangibles & other assets	50.5	51.8	47.4	Shareholders' equity	902.5	892.1	845.9
Total	2,608.9	2,591.7	2,819.3	**Total**	2,608.9	2,591.7	2,819.3

Ratio Analysis	12 mos ended	For the year ended December 31			
Liquidity Ratios	Mar. 2007	2006	2005	2004	2003
Current ratio	1.47	1.44	1.13	1.24	1.11
Total debt-to-capital (1)	57.4%	57.7%	59.0%	59.7%	61.2%
Cash flow/total debt (1)	16.4%	17.9%	16.6%	17.4%	20.9%
Cash flow/capital expenditures	1.08	1.18	1.44	1.93	2.27
(Cash flow-dividends)/capital exp.	0.83	0.93	0.95	1.48	2.23
Debt/EBITDA (1)	3.93	3.73	3.79	3.75	3.27
Common dividend payout ratio	68.2%	60.1%	106.3%	77.0%	4.9%
Deemed equity	35%	35%	35%	35%	35%
Coverage Ratios					
EBITDA interest coverage (1)	4.02	4.12	3.84	3.85	4.51
EBIT interest coverage (1)	2.21	2.39	2.27	2.25	2.94
Profitability/Operating Efficiency					
Operating margin	7.6%	8.6%	7.4%	8.9%	10.1%
Net margin (before extras.)	13.2%	14.8%	12.5%	12.5%	18.4%
Return on average equity (before extras.)	7.5%	8.9%	7.7%	8.0%	14.2%

Electricity Throughputs	2006	2005	2004	2003
Residential	5,352	5,724	5,412	5,408
General service	17,583	17,957	17,502	17,627
Large users	2,592	2,563	2,594	2,570
Street lighting	0	128	128	128
Total (million kWh)	25,527	26,372	25,636	25,733
Growth in electricity throughputs	-3.2%	2.9%	-0.4%	-2.2%

Customers	2006	2005	2004	2003
Residential	599,080	597,469	594,976	590,109
General service	78,978	79,162	78,150	78,517
Large users	49	47	47	47
Street lighting	1	1	1	1
Total	678,108	676,679	673,174	668,674
Growth in customer base	0.2%	0.5%	0.7%	0.6%

(1) DBRS adjusted for operating lease equivalents. Financial results reflect adjustment to exclude mark-to-market in revenues

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Note:
All figures are in Canadian dollars unless otherwise noted.

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STANDARD &POOR'S

RATINGSDIRECT

Hamilton Utilities Corp.

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Hamilton Utilities Corp.

Major Rating Factors

Corporate Credit Rating
A/Positive/--

Strengths:

- Monopoly electricity distribution assets
- Regulated cash flows
- Efficient, low-cost electricity distributor
- Risk-averse management team
- Strong balance sheet

Weaknesses:

- Exposure to unregulated operations
- Mature service territory with exposure to cyclical industries
- Lack of access to equity markets

Rationale

The ratings on Hamilton Utilities Corp. (HUC) reflect the company's strong business risk profile, which is supported by its low-risk regulated monopoly electricity distribution business; its good operational performance; and an intermediate financial risk profile. The company's unregulated and higher-risk data network and cogeneration activities, and its mature electricity service territory, offset these strengths somewhat.

HUC is a Hamilton, Ont.-based utility holding company. About 85% of the company's cash flows come from its majority ownership position (78.9%) in local electricity distribution company (LDC), Horizon Utilities Corp. Horizon serves about 227,000 customers in the Cities of Hamilton (AA/Positive/--) and St. Catharines (unrated), both of which are in southern Ontario.

The regulatory framework provides for the recovery of all prudent costs and a return on capital employed. The asset-intensive nature of the business and regulatory support mitigate the risks of bypass. Furthermore, the company faces limited risk related to commodity price and volume variability. Although Horizon bills electricity customers for the cost of the commodity consumed, the company has no obligation to ensure an adequate supply of electricity for its customers.

Horizon's electricity distribution assets exhibit solid operational performance. Reliability is better than the industry average. The LDC's above-average performance limits the potential risk to the company's cash flows from operational disruptions. Furthermore, as measured by controllable cost per customer, Horizon's distribution system is one of the more efficient in Ontario.

HUC's consolidated financial profile falls within the intermediate category, but is stronger than many of its Ontario peers. The company's risk-averse approach to management permeates its financial policies. Cash interest and debt coverage, which are above-average for Ontario LDCs, reflect the holding company's modest leverage. Cash flow credit metrics were somewhat inflated in 2006 compared with historical performance and expectations. Adjusted funds from operations (AFFO) interest coverage was strong at 5.3x in 2006, compared with historical performance in the range of 4x to 4.5x where it is likely to return in 2007 and 2008. Similarly, AFFO-to-total debt was 39% as

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of Dec. 31, 2006. We expect AFFO-to-total debt to return to its historical range of 25%-30%. Total debt-to-total capital decreased slightly to 31.7% from 33%. AFFO increased to C$41 million in 2006 from C$33 million in 2005 due to several unrelated factors, including increased revenue and other income, slightly decreased operating expenses, and C$2.8 million in regulatory cost recovery. Total debt outstanding remained stable at C$105 million, as the company financed about one-third of its C$34 million in capital expenditures in 2006 with cash on hand rather than new debt. Additions to the utility's regulated asset base, including the launch late in 2006 of provincially directed smart meter installations, accounted for the bulk of capital spending.

HUC's exposure to competitive-based and nonregulated operations weakens its business position, although the impact is modest. HUC's fiber optic network, which represents the bulk of the unregulated operations and contributes close to 10% of annual cash flows, does not benefit from regulatory price support and is potentially exposed to competitive pricing and the threat of new entrants. Furthermore, the company's district energy project remains a mild drain on cash flows.

Growth in Horizon's mature customer base averaged less than the provincial average of 1% per year for the past four years. Nevertheless, Hamilton's economy continues to benefit from its proximity to the Greater Toronto Area and access to the U.S. market. Despite the rise in energy prices and the value of the Canadian dollar, the city's steel sector continues to operate. Other key sectors, such as biotechnology and healthcare, figure prominently in the city's economic development strategy to increase diversification.

Liquidity

HUC maintains a good level of liquidity. The company can fully fund its capital expenditure commitments from internal sources. Liquidity is ample for its needs given, as of Dec. 31, 2006, C$100 million in unused bank lines, a cash balance of about C$33 million, and no debt maturities until 2012. We estimate annual FFO to be about C$40 million, and the company's cash position is likely to be sustainable at a level of about C$10 million. HUC has C$23.5 million of LOCs posted in prudential requirements with the Independent Electricity Systems Operator (IESO), which have a ratings trigger. Should the credit rating on the company fall below 'A-', the IESO would require HUC to post an additional C$23.5 million. The three-year bank line matures Jan. 31, 2009.

Outlook

The positive outlook reflects a steady improvement in HUC's business risk profile, as well as a stable consolidated financial profile. The improvement is largely a result of steadily increasing clarity and stability with regards to regulatory methodology and timetables that affect Horizon and the continued absence of further market restructuring and political involvement in the regulatory process. Should this trend continue, a positive rating action could result, but more than a single-notch improvement is highly unlikely. Downward pressure on the ratings could result from a material change in management's financial policy, an adverse regulatory ruling, or disruptive market restructuring.

Business Description

HUC is wholly owned by the City of Hamilton, which holds all of HUC's common shares outstanding. HUC has a commercially oriented board of nine directors, seven of whom have no ties to either HUC or the City of Hamilton. Standard & Poor's expects that a cash or equity injection from the city to maintain a particular credit rating is

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highly unlikely. Certain modest benefits associated with having a supportive shareholder have been incorporated into the ratings. Nevertheless, the ratings on HUC are largely based on the stand-alone credit quality of Horizon. HUC owns 78.9% of Horizon, with St. Catharine Hydro Inc. (SCHI; not rated) owning the remaining 21.1%. SCHI is wholly-owned by the City of St. Catharines.

In 2007 and 2008, we expect HUC's projected consolidated FFO to come from its:

- Low-risk distribution assets (88%);
- Fiber-optics subsidiary FibreWired (7%); and
- Energy services business (5%).

The regulated distribution operation is the third-largest municipal-owned electric utility in Ontario (based on customers), with about 229,000 customers and about 3,273 km of distribution lines, about half of which are underground. The company delivers about 7% of Ontario's electricity load. The FibreWired business provides a variety of local high-speed data telecommunications services to businesses and organizations, with revenues predominantly from the provision of transparent local area networks (LAN) or LAN extensions services, and Internet connectivity solutions. The relatively small energy services business consists of water heater rentals, heating energy, and administrative utility services.

Fully consolidating Horizon into HUC's financial profile is appropriate, given HUC's majority ownership, management influence, and effective control. HUC owns 78.9% of Horizon Utilities and holds the majority of seats on the LDC's board, with eight of 10. Furthermore, the use of back-to-back intercompany loans between HUC and the LDC with the same terms and conditions as HUC's existing bank and debenture facilities supports the servicing of external debt held at HUC.

Strong Business Risk Profile

Regulation a strong influence on profitability

The regulation of its LDC is a strong influence on HUC's profitability. Horizon's profitability is stable and largely dictated by regulatory directives, given the cost-plus nature of the Ontario regulatory framework and the role of the LDC within the electricity market. The OEB sets tariffs such that the utility should be able to recover prudent costs, including the cost of a deemed level of short and long term debt (60%) and equity (40%) capital. All else being equal, profitability in 2007 will be marginally less than in 2006, as the returns allowed for in the tariff setting process are linked to long-term borrowing rates which continued to decline year over year as of Jan 2007.

Profitability will vary somewhat depending on weather conditions. Regulated distribution tariffs have a fixed and variable component. The variable component is linked to the amount of electricity delivered to the customer. As such, hotter summers and colder winters contribute to marginally higher net income. The price of electricity does not affect the LDC's profitability, as the charge for energy is passed on to the consumer.

Regulation

The Ontario Energy Board (OEB) completed its Cost of Capital review in late 2006, resulting in minimal changes to the regulatory methodology approved by the OEB in 1998. The decision removed significant uncertainty that was hanging over the sector in 2006 as a result of OEB staff proposals to significantly lower equity risk premiums. The OEB's decision to maintain its formula for determining ROEs allowed for in the rate-setting process is an example of stability and consistency.

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The OEB's "2nd Generation Incentive Regulation Mechanism" provides regulatory stability while the regulator conducts several rate-related studies towards the goal of achieving a formulaic rate adjustment method that will add further to regulatory predictability and timeliness. A price cap adjustment mechanism for electricity distributors rather than a revenue cap will continue to be used in the near term. With the cap mechanism, the LDC's profitability is partially shielded from inflationary pressures, as price indices drive changes in tariffs they are allowed to charge for regulated services. Nevertheless, LDCs will face the challenge of meeting productivity improvements also factored into the tariffs.

Resourcing of the OEB has improved but remains strained by the number of LDCs in the sector, new responsibilities such as the regulatory oversight of Ontario Power Generation, and the implementation of performance-based regulation in both the gas and electricity sectors in the next several years.

The implementation, at the government's direction, of the OEB's Regulated Price Plan (RPP) smoothed consumer exposure to commodity volatility, thereby reducing, although not removing, the risk of political influence in the sector. Furthermore, the Ontario Power Authority now bears the bulk of any variance between the RPP price and the market price. Before 2004, the liquidity of some LDC had, at times, been pressured by regulatory delays to commodity cost recovery.

Markets: Mature service area

Despite a significant industrial load (at about 30% of energy distributed), the majority of Horizon's electricity network revenues come from residential consumers (see table 1). The benefit of providing an essential service such as electricity to residential consumers is that their energy consumption is more immune to economic cycles than that of industrial and commercial consumers. Reflecting HUC's mature service territory, annual growth in customer numbers is likely to be low at less than the provincial average of 1%. The unemployment rate is at about the national average of 6.7% and the average per capita income is 13% above the national average. The service territory of St. Catherines Hydro Inc.'s LDC exhibits similar demographic and growth characteristics.

Table 1

Horizon Utilities Corp.--Customer Profile 2006

	No. of customers	Customers (%)	Proportion of distribution revenue (%)	Proportion of electricity distributed (%)
Residential	209,370	90	72	26
General service	20,200	9	25	41
Large users	12	0	2	32
Sentinel, street lights, and other nonscattered load	2,056	1	1	1
Total	231,638	100	100	100

The fixed-rate structure applicable to large industrials minimizes the extent of revenue volatility resulting from cyclical electricity consumption. The top 10 industrial customers accounted for about 4% of net distribution revenues in 2006, with the largest individual user representing 1%.

The principal market served by HUC's FibreWired business is the local market of Hamilton. Revenue growth continued in 2006 at 12% as compared with 13% in 2005. The company launched a WiFi pilot project in Hamilton that will also facilitate the implementation of Ontario's government-directed smart meter implementation. Investment-grade counterparties in the private sector yield about half of revenue received; the balance comes from

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relatively stable public sector entities and the institutions sector including school boards, the City of Hamilton, Telus Corp. (BBB+/Stable/--), Telus Mobility, and Hamilton Health Sciences Corp.

Operations: Electricity distribution assets dominate

Low-risk electricity distribution assets dominate HUC' operations. The LDC operations provide about 88% of cash flows and represent close to 90% of asset value. The company's unregulated operations include its data network business (providing about 7% of cash flows), water heater rental business (2%), district heating and cogeneration facility (negative 1%), and other services such as back office services, and the provision of water billing services to the City of Hamilton (4%). The company does not engage in high-risk energy trading or mass market telecommunications activities.

The efficiency and reliability of its electricity distribution operations, and our expectation that they will continue to perform well, supports HUC's strong business profile. This view is further supported by operational performance at the LDC that in terms of reliability is better than industry averages as measured by the Canadian Electricity Association composite index (see table 2). Furthermore, based on standard industry performance measures, Hamilton Hydro is one of the lowest cost and most efficient distribution operators in Canada.

Table 2

Horizon Utilities Corp. Distribution Network Operational Performance

Reliability Measures	2006	2005	2004	2003	2002	2001
Customer average interruption duration index (minutes)	39.0	39.5	48.4	54.0	32.9	39.0
CEA Composite Index (minutes)	N/A	135.6	120.0	203.0	102.0	90.0
System average interruption duration index (minutes)	56.1	62.7	45.8	69.3	41.2	70.8
CEA Composite Index (minutes)	N/A	288	237.0	451.0	246.0	222.0
System average interruption frequency index (interruptions)	1.4	1.6	1.2	1.3	1.2	1.8
CEA Composite Index	N/A	2.13	2.0	2.2	2.3	2.4

CEA--Canadian Electricity Association. N/A--Not applicable.

HUC's capital expenditure commitments are modest at about 10% of total capital, consistent with the company's long-life assets. We expect annual underlying capital expenditure of just under C$30 million per year in 2007 and 2008, of which about 90% of expenditure will be invested in the regulated distribution assets. Of this, about one-third will go to non-discretionary growth capital expenditure.

HUC expects to spend an additional C$30 million-C$40 million on the government-directed installation of smart meters in a four-year period starting in late 2006. The cost of the initiative, which will retrofit all existing meters and be largely financed from internal cash flows, will be recovered through adjusted electricity distribution rates.

Unregulated businesses are likely to remain a meaningful but small proportion of the total business, representing less than 15% of HUC's total consolidated assets. Furthermore, management has generally taken a conservative approach to its unregulated businesses investments. Medium-term service contracts with investment-grade counterparties are designed to recover the initial capital investment and generate a reasonable return. A service agreement with the customer is required before any incremental investment in system infrastructure. Capital investment in FibreWired should not exceed C$2 million per year. Contracts underpinning the services provided by the FibreWired business are typically three to six years in duration.

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Negligible competition

HUC holds a monopoly in its electricity service territory, protecting the company's distribution franchise from rival network providers. Furthermore, the company's relatively low cost operations and tariffs guard against the threat of material bypass of the network. In addition, although the company's unregulated operations of data network services, district heating, and water heater rentals do not benefit from regulatory price support or restrictions on competition, HUC's position as the incumbent provider of the services mitigates the threat of competition. Hydro One (A/Stable/A-1), a transmission and distribution company owned by Ontario, serves about 25,000 customers within Horizon's borders. This is not a reflection of competitive forces but rather the legacy of a provincially directed 2002 municipal amalgamation.

Intermediate Financial Risk Profile

Accounting

HUC's consolidated financial statements are prepared in accordance with Canadian GAAP with a Dec. 31 fiscal year end. We expect no material changes in 2007 to Canadian GAAP or the accounting policies adopted by HUC that would materially alter the financial statements as presented by HUC. Cash recovery in 2006 of market transition costs (approved by the regulator) was reflected on the income statement. The C$2.7 million impact on FFO resulted in a mild enhancement to cash flow credit metrics but did not affect the ratings. The utility has no exposure to derivatives.

Corporate governance, risk tolerance, and financial policies

The company's governance does not exhibit any features that raise credit concern. The directors for HUC and Horizon are largely independent. The HUC board consists of 9 commercially-oriented members, eight of which are independent of both the shareholder and the company. The mayor of Hamilton (or the mayor's designate) is a member of the board.

The company is risk-conscious, as reflected in its conservative financial profile and development of its fiber optic data network by leveraging off its existing infrastructure rather than building out the network to attract new customers. HUC faces very modest counterparty risk associated with major energy customers that procure their energy through Horizon, a nonregulated entity.

HUC's financial risk profile is intermediate. The company has taken steps to reduce its risk by maintaining a conservative debt leverage position at the consolidated level. As a result, HUC has one of the stronger intermediate financial risk profiles of Canadian regulated utilities. In line with peers, HUC's current dividend policy is based on distributing up to 60% of annual net earnings.

Cash flow adequacy: regulation provides stability

The bulk of HUC's revenues are either regulated or contracted, and therefore provide relative cash flow stability. Conservative leverage position ensures strong interest and debt cash flow coverages. The company's consolidated AFFO should be sustainable at about C$40 million per year in 2007 and 2008.

We expect the cash drain from HUC by way of higher-than-average capital expenditure and dividends to continue. Nevertheless, we expect the company to be in a position to largely finance from internal cash flow all its annual capital expenditure without recourse to external funding. In the next few years, absent any special dividends, net cash flow-to-capital expenditure should not dip materially below 100%. Forecast annual dividends are average for

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the industry, at up to 60% of net income.

Capital structure and asset protection: conservative balance sheet maintained

We expect HUC to maintain a conservative balance sheet, with consolidated leverage as measured by total debt-to-total capital expected to eventually fall in the 45%-50% range. Further debt-financed mergers or acquisitions at Horizon could serve to bring leverage into this range from its current level of closer to 30%. The company faces no material debt refinancing in the short-to-medium term with the bulk of debt outstanding, represented by a C$105 million debenture, due in 2012. Furthermore, with largely fixed-rate Canadian dollar-denominated debt, HUC has no material interest rate exposure and no foreign exchange exposure.

HUC's financial flexibility is adequate. Supporting the utility's financial flexibility are the company's unused bank lines of C$100 million. In addition, the company's cash balance, which stood at about C$33 million at Dec. 31, 2006, provides a ready source of funds in the short term. HUC expects a sustainable cash position of about C$10 million. A capacity to draw down additional debt through its bank lines and issue through its trust indenture also supports HUC's financial flexibility. Also, in the short term, the company can defer capital expenditure in the C$15 million-C$20 million range, which is more than its annual interest expense. A limitation on its ability to source additional direct equity, however, is a relative constraint for the company's financial flexibility. Despite an expectation that no direct equity investment will be forthcoming from the City of Hamilton, the company expects to have some flexibility to reduce dividends in times of financial stress.

Table 3

Hamilton Utilities Corp.--Peer Comparison*

	--Average of past three fiscal years--			
	Hamilton Utilities Corp.	**Toronto Hydro Corp.**	**Hydro Ottawa Holding Inc.¶**	**Enersource Corp.¶§**
Rating as of March 30, 2007	A/Positive/--	A-/Positive/--	A-/Positive/--	A-/Positive
(Mil. C$)				
Total revenues	499.4	2,361.9	639.4	688.8
Net income from continuing operations	13.2	92.9	13.6	10.5
Funds from operations (FFO)	34.3	232.6	44.0	47.5
Capital expenditures	24.6	165.8	70.3	30.6
Cash and investments	48.3	387.5	0.0	44.0
Debt	105.0	1,327.0	234.7	291.3
Common equity	181.7	832.7	217.2	198.2
Total capital	309.4	2,159.8	452.0	489.8
Adjusted ratios				
EBIT interest coverage (x)	3.4	2.7	2.1	2.0
FFO interest coverage (X)	4.8	3.4	3.8	3.7
FFO/debt (%)	32.6	17.5	18.8	16.3
Discretionary cash flow/debt (%)	3.6	(0.1)	(1.8)	7.6
Net cash flow/capex (%)	85.1	107.4	62.6	128.2
Debt/total capital (%)	33.9	61.4	51.9	59.5
Return on common equity (%)	7.8	11.2	6.2	5.0
Common dividend payout ratio (unadjusted) (%)	78.5	58.6	0.0	78.1

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Table 3

Hamilton Utilities Corp.--Peer Comparison* (cont.)

*Fully adjusted (including post-retirement obligations). ¶Average of the three years ended 2003-2005. §Rating reflects senior secured Borealis-Enersource series bonds issued by Borealis Infrastructure Trust (Enersource Mississauga tranche).

Table 4

Hamilton Utilities Corp.--Financial Summary*

	Average of past three fiscal years	--Fiscal year ended Dec. 31--					
(Mil. C$)	N/A	**2006**	**2005**	**2004**	**2003**	**2002**	**2001**
Rating history	N/A	A/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--	A+/Watch Neg/--	N.R.
Total revenues	499.4	536.3	566.8	395.1	394.6	469.4	477.4
Net income continuing	13.2	16.2	12.4	11.0	8.2	8.5	7.0
Funds from operations (FFO)	34.3	41.2	33.4	28.2	25.6	22.7	25.8
Capital expenditures	24.6	33.9	21.5	18.4	26.3	26.1	27.3
Cash and investments	48.3	33.3	46.6	64.9	42.7	16.0	67.8
Debt	105.0	105.0	105.0	105.0	105.5	106.1	138.7
Common equity	181.7	191.5	180.0	173.5	165.2	158.7	149.7
Total capital	309.4	331.5	318.2	278.5	270.6	264.8	288.4
Adjusted ratios							
EBIT interest coverage (x)	3.4	3.9	3.4	3.0	2.6	2.5	2.5
FFO interest coverage (x)	4.8	5.3	4.6	4.3	4.0	3.5	9.0
FFO/debt (%)	32.6	39.3	31.8	26.9	24.2	21.4	18.6
Discretionary cash flow/debt (%)	3.6	(13.5)	6.8	17.5	17.6	(22.7)	(0.1)
Net cash flow/capex (%)	85.1	106.9	6.3	137.1	88.7	87.0	87.5
Debt/total capital (%)	33.9	31.7	33.0	37.7	39.0	40.1	48.1
Return on average equity (%)	7.8	9.2	7.4	6.8	5.3	5.8	5.0
Common dividend payout ratio (unadjusted; %)	78.5	30.9	186.7	27.2	27.4	0.0	27.2

*Fully adjusted. N/A--Not applicable. N.R.--not rated.

Table 5

Reconciliation Of Hamilton Utilities Corp.'s Dec. 31, 2005, Reported Amounts With Standard & Poor's Adjusted Amounts*

Hamilton Utilities Corp. reported amounts (mil. C$)	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expenses**	**Operating cash flows**	**Operating cash flows**
	181.2	55.6	55.6	33.2	8.1	24.9	24.9
Standard & Poor's adjustments							
Post-retirement benefit obligations	10.2	1.1	1.1	1.1	1.0	(0.2)	(0.2)
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	1.3	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	17
Minority interest	35.0	N/A	N/A	N/A	N/A	N/A	N/A

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Table 5

Reconciliation Of Hamilton Utilities Corp.'s Dec. 31, 2005, Reported Amounts With Standard & Poor's Adjusted Amounts* (cont.)							
Standard & Poor's total adjustments	10.0	1.0	1.0	2.1	1.0	(0.1)	(27.4)

Standard & Poor's adjusted amounts	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expenses	Operating cash flows	Funds from operations
	226.5	56.6	56.6	35.6	9.1	24.7	41.2

*This table illustrates the adjustments made by Standard & Poor's to the company's reported amounts for the year ended Dec. 31, 2005. The first section headed "Hamilton Utilities Corp. reported amounts" describes and shows amounts as reported by the company. The second section, headed "Standard & Poor's adjustments," shows our adjustments to these reported amounts. The third section, headed "Standard & Poor's adjusted amounts," describes and shows the amounts we use to calculate the fully adjusted ratios appearing elsewhere in this report. Please note that two reported amounts (operating income before D&A, and operating cash flows) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and operating cash flows and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. N/A--Not applicable.

Ratings Detail (As Of April 19, 2007)*	
Hamilton Utilities Corp	
Corporate Credit Rating	A/Positive/--
Senior Unsecured	
Local Currency	A
Corporate Credit Ratings History	
26-Mar-2007	A/Positive/--
16-May-2003	A/Stable/--
13-Nov-2002	A+/Watch Neg/--
Financial Risk Profile	Intermediate
Related Entities	
Hamilton (City of)	
Issuer Credit Rating	AA/Positive/--

*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.

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March 3, 2008

Research Update:

Hydro One Inc. Issue Assigned 'A' Rating; Other Ratings Affirmed

Primary Credit Analyst:
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Research Update:

Hydro One Inc. Issue Assigned 'A' Rating; Other Ratings Affirmed

Rationale

On March 3, 2008, Standard & Poor's Ratings Services assigned its 'A' debt rating to Hydro One Inc.'s C$250 million three-year note (due 2011). At the same time, Standard & Poor's affirmed its other ratings on Hydro One, including the 'A' long-term corporate credit rating. We also affirmed the 'A' debt rating on the company's C$600 million 10-year note due 2017, following the addition of C$300 million to the note. The debt ratings mirror the ratings on existing senior unsecured debt obligations. The regulated utility will use the proceeds to refinance maturing debt and for general corporate purposes. The outlook is positive.

The ratings reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the Province of Ontario (AA/Stable/A-1+). Offsetting these strengths is an intermediate financial risk profile that will face challenges from the company's large capital expenditure program in the next several years. Hydro One had C$5.6 billion in debt outstanding as of Dec. 31, 2007.

Hydro One's monopoly position, the business' asset-intensive nature, and regulatory oversight limit competitive risk. Hydro One is the incumbent electricity transmission business and largest distributor of electricity in Ontario. The company owns and operates more than 97% of the province's transmission network as measured by revenue, and its distribution network service territory covers about 75% of the province.

The regulated returns Hydro One receives from its electricity delivery businesses support the company's debt-servicing capacity. Secure and relatively predictable regulated cash flows are supported by cost-of-service and rate-of-return regulation directed by the Ontario Energy Board (OEB). The company can expect to recover all prudent costs incurred and earn a modest return on its capital investment. Furthermore, the company faces limited risk related to commodity price and volume variability. Although Hydro One's distribution business bills customers for the cost of the commodity consumed, the company has no obligation to ensure adequate electricity supply.

Hydro One has an intermediate financial risk profile, and cash flow interest and debt coverages could weaken in the next few years. Sustainable adjusted funds from operations (AFFO) interest coverage of 4.1x as of Dec. 31, 2007, was similar to the 3.9x level at year-end 2006. The minor change in sustainable AFFO interest coverage was largely a result of lower pension adjusted interest expense. These figures exclude cash flow recovery of deferred revenue and retail settlement regulatory variance accounts. Including these, AFFO interest coverage was 4.5x in 2007, up from 4.0x in 2006. This reflects higher regulatory cost recovery in 2007 (C$120 million) than in 2006 (C$40 million).

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Sustainable AFFO interest coverage should drift downward in the next several years. The extent of the decline in the utility's cash flow strength will depend on regulatory approvals and execution of planned capital expenditures, the impact of weather variability on revenue, and the company's ability to find operating efficiencies sufficient to offset the OEB's performance-based regulatory pressures on rates. AFFO-to-total debt should remain within the 12%-14% range compared with its 2007 level of 16%. We expect the company to debt finance 20% or more of forecast capital expenditure during the expansion period. Hydro One's leverage, as measured by adjusted total debt-to-total capital, is also likely to creep back up to the historical level of about 64%, compared with 58% in 2007.

The province's ownership of Hydro One enhances the utility's credit quality. Although Ontario does not formally guarantee Hydro One's debt obligations, the strategic nature of the company within the provincial economy and the government's demonstrated willingness to assist the business (with liquidity support) under extraordinary circumstances in the past bode well for future support of a similar nature.

Although predominantly funded from internal sources, capital spending during the next few years will be a drain on the company's cash flow, reducing financial flexibility. The utility has budgeted C$1.4 billion in capital expenditure for 2008, higher than historical average. Increased capital spending will fund upgrades and expansion of the transmission system to accommodate: new generation, increased imports and exports, and modest growth in domestic demand. The 2008 capital program also includes a portion of the estimated remaining C$670 million investment that Hydro One will make in smart meters for all distribution customers by 2010.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and access to the debt capital markets, provide Hydro One with sufficient liquidity and the financial flexibility to meet the company's estimated capital expenditure of C$1.4 billion, annual dividend payments of C$250 million-C$290 million, and C$540 million of debt maturing in 2008. Furthermore, the company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

To support liquidity, the company can draw on:

- A committed bank line of C$1 billion (maturing August 2010) that remained largely available at the time of publication. The bank line is used for general corporate purposes and to support Hydro One's C$1 billion Canadian commercial paper program. The line increased to C$1 billion from C$750 million as of Jan. 28, 2008.
- Annual regulated cash flows, as represented by unadjusted FFO, estimated at about C$900 million in 2008;
- A medium-term note shelf program, maturing in July 2009, that had C$1.65 billion remaining capacity as of today's issuance; and
- Discretionary capital expenditure estimated at more than C$200 million in 2008.

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Outlook

The positive outlook reflects a steady improvement in Hydro One's business risk profile. The improvement is largely a result of steadily increasing clarity and stability with regards to regulatory methodology and timetables that influence both the transmission and distribution business, and the continued absence of disruptive market restructuring and political involvement in the regulatory process. Should this trend continue, it could result in a positive rating action, but more than a single-notch improvement is unlikely. Given the supportive and stable shareholder relationship, the expected temporary downward pressure on the company's cash flow strength due to the pressures of upcoming increased capital spending should not lead to a revised outlook. A material change in the company's financial risk or business risk profile, possibly from an adverse regulatory ruling, market restructuring, or its shareholder relationship, could lead to a negative rating action.

Ratings List

Hydro One Inc.

Rating Assigned	
C$250 million 4.08% MTN due 2011	A
Ratings Affirmed	
Corporate credit rating	A/Positive/A-1
Senior unsecured debt	A
C$600 million 5.18% MTN due 2017	A
Commercial paper	
Global scale	A-1
Canadian scale	A-1(Mid)

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STANDARD &POOR'S

RATINGSDIRECT®

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Summary:

Hydro One Inc.

Credit Rating: A/Positive/A-1

Rationale

The ratings on Ontario-based Hydro One Inc. reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the Province of Ontario (AA/Stable/A-1+). Offsetting these strengths is an intermediate financial risk profile that will face the challenges of a lower rate of return on its transmission rate base and the company's large capital expenditure program in the next several years. Hydro One had C$5.2 billion in long-term debt outstanding as of Dec. 31, 2006.

Hydro One's monopoly position, the asset intensive nature of its businesses, and regulatory oversight limit competitive risk. It is the key electricity transmission provider and largest distributor of electricity in the province. The company owns and operates more than 97% of Ontario's transmission network as measured by revenue, and its predominantly rural distribution service territory incorporates about 75% of the province as measured by surface area.

Hydro One's debt-servicing capacity relies on secure and relatively predictable regulated cash flows supported by cost-of-service plus rate-of-return regulation. The company can expect to recover all prudent costs incurred and earn a modest return on its capital investment. Furthermore, the company faces limited risk related to commodity price and volume variability. Although Hydro One's distribution business bills customers for the cost of the commodity consumed, the company has no obligation to ensure adequate electricity supply.

Provincial ownership enhances the utility's credit quality. Although Ontario does not formally guarantee Hydro One's debt obligations, the company's strategic nature within the provincial economy and the government's demonstrated willingness to financially assist the business under extraordinary circumstances in the past bode well for future support.

Hydro One has an intermediate financial risk profile. We expect weaker cash flow interest and debt coverage in the next few years due to a recent transmission revenue decision that lowered the allowed ROE on transmission assets to 8.35% from 9.88%, further exacerbated by the upcoming period of higher-than-normal capital expenditures. Adjusted funds from operations (AFFO) interest coverage of 4.6x in 2006 was up from 4.4x in 2005 largely as a result of distribution rate increases in 2005 and 2006 and regulatory asset recovery. AFFO interest coverage will drift downward in the next several years, and could fall below 3.5x. AFFO-to-total debt could also weaken to the 14%-17% range, compared with its 2006 level of 20%. The extent of the deterioration will depend on the timing of regulatory approvals and execution of budgeted capital expenditures, and the impact of weather variability on revenue. The company expects to debt finance 20% or more of forecast capital expenditure during the upcoming period of significant expansion. During this period, Hydro One's leverage, as measured by adjusted total debt-to-total capital, could creep back up closer to the historical level of about 64%, compared with 60% in 2006.

Although predominantly funded from internal sources, capital spending during the next few years will be a drain on

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the company's cash flow and reduce its financial flexibility. Hydro One has budgeted C$1.4 billion in capital expenditure for 2008, a 70% increase compared with the C$823 million spent in 2006, and higher-than-historical average. This period of increased capital spending is a result of planned upgrades and expansion of the transmission system to accommodate: growth in domestic electricity demand, the connection of new generation facilities, and facilitate increased imports and exports. The 2008 capital program also includes a portion of the estimated C$700 million investment that Hydro One will make in smart meters for all distribution customers by 2010 in the next four years. Like its other infrastructure investments, Hydro One's investment in smart meters will also be added to its revenue-generating regulated asset base.

Short term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and ready access to the debt capital markets, provide the utility with sufficient liquidity and the financial flexibility to meet its forecast capital expenditure estimate of C$1.2 billion, annual dividend payments of C$250 million to C$350 million, and C$355 million of debt maturing in 2007. As of Sept. 30, 2007, C$161 million had been drawn from the company's C$1 billion short-term note program. The company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

In support of Hydro One's liquidity, the company can draw on:

- A committed C$750 million bank line of which C$589 million was available as of Sept. 30, 2007. The bank line is used for general corporate purposes and to support its C$1 billion Canadian CP program. The line matures in August 2010;
- Its expected annual regulated cash flows as represented by unadjusted FFO of about C$860 million in 2007;
- C$2.2 billion remaining capacity on a C$2.5 billion MTN shelf program, maturing in July 2009; and
- Discretionary capital expenditure estimated at C$150 million- C$200 million.

Outlook

The positive outlook reflects a steady improvement in Hydro One's business risk profile. The improvement is largely a result of steadily increasing clarity and stability with regards to regulatory methodology and timetables that influence both the transmission and distribution business, and the continued absence of disruptive market restructuring and political involvement in the regulatory process. Should this trend continue it could result in a positive rating action, but more than a single-notch improvement is highly unlikely. Given the supportive and stable shareholder relationship, the temporary downward pressure on the company's cash flow strength due to the pressures of upcoming increased capital spending should not lead to a revised outlook. A negative rating action could result from a material change in the company's financial or business risk profile or its shareholder relationship, an adverse regulatory ruling, or unfavorable market restructuring.

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STANDARD &POOR'S

RATINGSDIRECT®

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Hydro Ottawa Holding Inc.

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Summary:

Hydro Ottawa Holding Inc.

Credit Rating: A-/Stable/--

Rationale

The ratings on Ottawa, Ont.-based utility holding company Hydro Ottawa Holding Inc. reflect the stable, regulated cash flows from its monopoly electricity distribution business, average regulatory regime, low-cost and reliable operations, and solid interest and debt coverage ratios. These strengths are offset by the need for increased capital expenditures to refurbish its mature asset base and exposure to unregulated higher risk data network and electricity generation operations.

The bulk (about 90%) of the company's cash flows comes from its low-risk electricity network subsidiary, which serves almost 90% of the City of Ottawa's (AA+/Stable/--) customer base. The company's monopoly position within its current franchise, and its regulated distribution tariffs, mitigate the risk of any material bypass of the network. The regulated returns from the network business also provide stability and predictability to the company's cash flows.

The regulatory regime governing Hydro Ottawa's local electricity distribution company's (LDC) operations is generally supportive of credit quality. The regulatory framework provides for the recovery of all prudent costs and a return on capital employed through distribution tariffs approved by the Ontario Energy Board. Furthermore, Hydro Ottawa's LDC faces no commodity exposure, with all energy costs fully passed through to the end user. The provincial government has taken positive steps to address what has been a regulatory regime lacking in independence and stability. Nevertheless, the regime continues to face potential political interference.

Hydro Ottawa's low-cost distribution operations and good operational performance provide some buffer to the significantly higher-than-historical capital spending required to rejuvenate the aging regulated assets and maintain reliability. Even after implementing a rate increase in May 2006, the LDC's distribution tariffs are still among the lowest in the province. Furthermore, the distribution network's system reliability is better than the industry average, and historical operating costs and staff complement compare well with Ontario peers on a per-customer basis. Ongoing annual capital expenditure for the network business could increase significantly in the next few years, subject to regulatory approvals.

Hydro Ottawa's financial profile is characterized by solid credit metrics. The overall financial profile of the company is not expected to differ significantly in 2006 compared with 2005. Excluding the positive effect of the recovery of regulated assets of C$7 million in 2005, consolidated funds from operations (FFO) interest coverage was about 5.0x at year-end 2005, which was as expected and much improved from 3.6x in 2004. FFO-to-average total debt was 23%, also as expected. Improved FFO interest coverage can be attributed in large part to increased FFO and reduced interest expense, a result of the refinancing of the company's debt outstanding in 2005. The improved financial strength in 2005 and 2006 is offset by the OEB's plans, as of May 2007, to implement second-generation performance-based regulation that could negatively affect the LDC's future cash flow coverage. The holding company's total debt-to-total capital at year-end 2005 on a consolidated basis was 45%, but should range closer to 50%-55% in the near term. Third-quarter (ended Sept. 30) results were in line with expectations.

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If the holding company's financing needs (related to its capital expenditure program) increase as forecast and are met solely with debt capital, short-term borrowing will increase, financial flexibility will decrease, and the balance sheet is likely to face pressure toward the end of the decade. Offsetting this risk somewhat is the bulk of Hydro Ottawa's forecast capital expenditure, which centers on its regulated electricity network and will serve to increase regulated revenue in the long term. Net cash flow-to-total capital expenditure could average as low as 55% during this period. Buildout of the company's telecommunications infrastructure is complete; therefore, related capital spending in the next few years, primarily driven by new customer connections, is expected to be minimal and internally funded by the telecom subsidiary. Hydro Ottawa's energy subsidiary has a small landfill gas generation under development that is forecast to be in service in early 2007 at a cost of C$7 million.

Although Standard & Poor's Ratings Services expects the LDC to remain the company's key business and cash provider, Hydro Ottawa's exposure to its competitive-based operations weakens its business position. The small data network business is price-competitive, but remains subject to recontracting risk and does not benefit from regulatory price support. The company's high-risk hydroelectric operations are price-competitive, but related cash flows are exposed to significant variability due to hydrology risk and the volatility of wholesale electricity prices.

Liquidity

Hydro Ottawa maintains average liquidity, with annual operating cash flows and available financing sufficient to meet capital expenditure and dividend commitments. The company does not face any near-term debt maturities. Hydro Ottawa's single senior unsecured debt issue of C$200 million matures in 2015. FFO at the LDC of about C$60 million forecast for 2006 will be insufficient to fully fund its C$80 million capital program; therefore, short-term borrowings are expected to increase during 2006. As of Sept. 30, 2006, after posting C$22 million in LOCs in prudential requirements with Ontario's Independent Electricity System Operator (IESO), the company had about C$95 million available through its C$150 million committed facility that expires in January 2008. Hydro Ottawa also had access to C$15.8 million available through its C$25 million line demand facility. Should all credit ratings on Hydro Ottawa issued by rating agencies fall below 'A-', the IESO would require the company to post an additional prudential of C$22 million. Cash dividends of C$12 million were paid for the first time in April 2006.

Outlook

The stable outlook reflects Standard & Poor's expectations of no material change in the holding company's business and financial risk profiles, the stability of Hydro Ottawa's predominantly regulated cash flows, and the company's moderate growth strategy to minimize volatility in future nonregulated cash flow through medium- and long-term contracts. An outlook revision to positive or an upgrade is unlikely, given the financial constraints imposed by the Ontario regulatory framework and significantly increased capital expenditures geared at replacing the LDC's aging assets. A material debt-financed acquisition or exposure to increased business and financial risk associated with the company's unregulated activities could have a negative effect on ratings.

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STANDARD &POOR'S

RATINGSDIRECT®

November 12, 2007

Toronto Hydro Corp.

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Toronto Hydro Corp.

Major Rating Factors

Corporate Credit Rating
A-/Positive/--

Strengths:
- Monopoly position
- Stable cash flows supported by cost-of-service regulation
- Low-risk electricity distribution assets
- Favorable service territory

Weaknesses:
- Intermediate financial risk profile
- Aging infrastructure and labor demographics

Rationale

The ratings on Toronto Hydro, an Ontario-based utility holding company, largely reflect the strong business risk profile of its key subsidiary, Toronto Hydro-Electric System Ltd. (THESL). THESL's business risk profile reflects its low-risk regulated electricity distribution business and solid customer base. These strengths are offset by Toronto Hydro's intermediate financial risk profile and, to a lesser extent, the holding company's involvement in higher-risk unregulated business activities. Total debt outstanding as of Dec. 31, 2006, was about C$1.2 billion, including C$225 million of external debt and C$980 million held by the city.

THESL's regulated cash flows underpin Toronto Hydro's debt servicing capability. The local distribution company (LDC) accounts for about 98% of consolidated assets and close to 85% of cash flows. The Ontario Energy Board sets distribution tariffs through a cost-of-service and rate-of-return methodology. The asset-intensive nature of the business and regulatory support mitigate the risks of bypass. Furthermore, the company faces limited risk related to commodity price and volume variability. Although THESL bills customers for the commodity, the regulatory framework supports full and generally timely pass through of these costs. Furthermore, THESL has no obligation or long-term commitments to ensure adequate electricity supply.

The LDC's solid customer base also contributes to cash flow stability. Its attractive service territory is the municipal boundary of the City of Toronto, with a customer base of about 680,000. Toronto's population has been growing at close to 1% annually. The Greater Toronto Area's economy is deep and well-diversified. Finance, manufacturing, and business and professional services are the foundations of the city's economy.

Standard & Poor's Ratings Services expects Toronto Hydro's intermediate financial risk profile and consolidated cash flow credit metrics to remain stable in the next few years. Consolidated adjusted funds from operations (AFFO) interest coverage and AFFO-to-total debt for 2006 were in line with our expectations and slightly higher than the company's 2005 results. AFFO interest cover increased to 3.7x in 2006 from 3.3x in 2005 and AFFO-to-total debt increased to 19% from 17%. These metrics reflect underlying cash flows from operations and do not incorporate annual cash recovery of regulatory assets of about C$20 million per year in the 2006-2008 period. We treat the company's promissory notes as debt and adjust for postretirement benefit obligations of about C$107 million, at year-end 2006. On this basis, the company's leverage was marginally lower at 61%.

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The holding company's ongoing interest in higher-risk unregulated activities weakens its business risk profile. The company has completed the planned phase-out of its unregulated competitive energy retailing business and sold its water heater business. Nevertheless, management is open to participating in greenfield, contracted electricity generation. Toronto Hydro's nonregulated holdings also include a relatively small but growing telecommunications business and build-out of a WiFi network. The company also provides street lighting services to the City of Toronto.

Liquidity

Toronto Hydro's liquidity is adequate. As at June 30, 2007, the company had C$352 million in cash and equivalents. Toronto Hydro also had access to C$420 million of remaining capacity through its C$500 million three-year revolving facility. Expected FFO, coupled with cash recovery of regulatory assets of about C$20 million in 2007, will not fund Toronto Hydro's forecast capital expenditure of about C$235 million and dividend payments of less than C$50 million. The company is well within the financial covenants applicable to its major banking facility.

Outlook

The positive outlook reflects a modest and steady improvement in the business risk profile and a stable consolidated financial risk profile. The improvement is largely a result of steadily increasing clarity and stability with regard to regulatory methodology and timetables that affect THESL and the holding company's completed exit from its high-risk energy retailing business. Continued improvement in Toronto Hydro's business risk profile could result in a positive rating action, but more than a single-notch improvement is highly unlikely. A material change in the company's financial risk or business risk profile, possibly from an adverse regulatory ruling, a material investment in nonregulated generation, or market restructuring could lead to a negative rating action.

Business Description

Toronto Hydro is a utility holding company that was incorporated in 1999 as a result of a change in Ontario law. The company's primary operation is THESL's monopoly electricity distribution business. Toronto Hydro is Ontario's largest local electricity distribution company, with more than C$2 billion in assets and delivering approximately 20 per cent of the electricity used in the province. The electricity distribution business delivers electricity throughout the City of Toronto and had a peak demand of 5,018 MW in 2006, similar to 2001. The system consists of 16,700 km of overhead and underground distribution lines. Other, much smaller subsidiaries include Toronto Hydro Energy Services Inc. (includes street lighting activities) and Toronto Hydro Telecom Inc.

Toronto Hydro is wholly owned by the City of Toronto (AA/Stable/A-1+). The city holds all the common shares outstanding in Toronto Hydro and a C$980 million demand promissory note of which C$245 million will be repaid on Dec. 31, 2007 with public debt already raised by the utility.

Strong Business Risk Profile

Regulatory framework supports cost recovery

THESL's regulated distribution revenues provide cash flow stability to Toronto Hydro. THESL's revenue is based on a cost-of-service and rate-of-return methodology that allows the subsidiary to recover all prudent costs and to earn a return on capital invested.

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The Ontario regulatory framework governing THESL's electricity distribution pricing is transparent and consistent. Political intervention marred the regime throughout 2002 and 2003; however, steps have been taken by the government to restore stability to the sector including a greater level of independence and better resourcing for the Ontario Energy Board (OEB).

The methodology and timing of upcoming rate decisions is now much clearer. The number of recently completed overarching regulatory decisions supports our expectation of ongoing improvement in timeliness. The regulatory calendar for the next two years is set, the regulator's workflow is more manageable, and we expect that ongoing process improvements will continue to reduce regulatory lag.

The trend for regulatory independence is also positive. The implementation, at the government's direction, of the OEB's Regulated Price Plan (RPP) has smoothed consumer exposure to commodity volatility and thereby reduced, although not removed, the risk of political influence in the sector. Furthermore, the Ontario Power Authority (an agency of the province) now bears the bulk of any variance between the RPP price and the market price. Before 2004, some LDCs' liquidity had, at times, been pressured by delayed and uncertain commodity cost recovery due to government-imposed rate freezes.

Mature customer base adds to credit stability

Toronto Hydro's strong business risk profile is supported by the stable service franchise of its regulated electricity distribution business. The company distributes electricity in the City of Toronto, which is a mature market characterized by low growth. Although the number of customers has grown by about 2%, the company's customer profile has not changed meaningfully in the past five years. Growth in the number of distribution customers has been between 0.2%-0.7% in each of the past four years. Total energy delivered in 2006 of 25.5 terawatt-hours (TWh) was about the same as in 2004, but about 3% less than in 2005. The fluctuations in energy delivered are primarily weather related and do not significantly affect profitability.

The LDC's customer base is predominantly residential and is therefore not heavily influenced by cyclical energy consumers potentially affected by economic conditions. The company provides electricity to about 678,000 customers concentrated in a small geographic area, of which about 597,000 are residential customers. Toronto Hydro's large users segment accounts for less than 10% of gross revenues. Furthermore, no single customer represents more than 1% of gross revenue.

Toronto Hydro does not face significant customer concentration risk, with its 10 largest customers accounting for about 4% of energy demand and about 3% of gross revenue. Small-to-midsize businesses represent only 12% of customers, but almost 70% of throughput and a similar proportion of gross revenues (about 65%). The diversification of this segment of the utility's customer base helps to somewhat mitigate the company's exposure.

Toronto Hydro's other activities are competitively based, and include the nonregulated provision of street lighting, telecommunications, and energy engineering solutions. These businesses are largely undertaken within the municipal boundaries of the City of Toronto. Standard & Poor's views the bulk of the unregulated activities undertaken as having higher risk characteristics.

Operations challenged by aging workforce and assets

Toronto Hydro's low-risk electricity distribution business dominates its operations. The distribution assets represent about 98% of the company's C$2 billion in fixed assets, with the contribution to cash flows from the unregulated business constituting 10% or less of the total.

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The number of full-time employees has fallen by 3% since 2002, but has increased marginally in each of the last three years. This trend is likely to continue and strengthen for the next three years, as the company hires staff to replace its aging workforce. Because of the multi year training required to fully qualify electric line maintainers, we will not see a return to current staff levels until post 2010.

The operational performance of Toronto Hydro's electricity distribution assets remains relatively steady and exceeds the composite index for Canadian utilities. Although the overall distribution system continues to perform well, the company's annual capital spending will continue to be higher than average for the next two to three years to ensure aging assets are replaced in a timely manner. After assessing the condition of its entire asset base, the utility filed a 10-year, C$1.3 billion capital plan with the Ontario Energy Board.

Toronto Hydro's business risk and financial risk profiles face medium-to-long-term risk due to the ongoing rationalization within the Ontario LDC sector. Toronto Hydro's likely participation in mergers or acquisitions of neighboring utilities could present financing, execution, and integration risks.

Minimal competitive risk exposure

Toronto Hydro's natural monopoly electricity distribution business largely shields the company from direct competition. The company's cost-competitive network pricing mitigates the incentive for bypass of the distribution network. Competitive risk is minimal given the large capital cost involved in duplicating the asset-intensive distribution system. Furthermore, natural gas has long been available in Toronto, so electricity market share loss to alternative energy providers is not a significant concern.

Modest But Stable Profitability

Toronto Hydro's profitability is modest but stable. THESL is the company's profit engine. Its modest profitability is driven by constraints in the Ontario regulatory framework and the company's ability to meet its own cost forecasts. The regulator designs distribution tariffs that allow the utility on average to recoup its cost of service plus a modest return (9% in 2007) on a moderate equity layer. If the utility modestly over- or under-earns in any one year, there are no regulatory consequences or offsets, although this could change in the next few years if the OEB implements performance related incentive mechanisms.

Earnings variability is largely due to the impact of weather on energy consumption and the modest volume sensitivity built into net distribution tariffs. Gross revenues are not a good indication of profitability; they are dominated by the much more significant commodity costs that are a flow through for THESL. THESL does not earn a return on the billed cost of energy delivered.

THESL has chosen to submit a three-year cost-of-service application to the Ontario Energy Board. The application addresses Toronto Hydro's need to renew its work force and ramp up its capital spending for the next decade. The OEB will conduct a hearing in December 2007 and could choose to approve a single- or multi-year revenue requirement and related rate increase. In years that the utility does not reapply to the regulator for a rate increase, the OEB has implemented an automatic tariff adjustment that allows for inflationary costs minus a productivity factor. This new mechanism could erode the utility's profitability if Toronto Hydro cannot find operational savings. The utility would be challenged to find savings as labor costs, the bulk of utility operating costs, generally increase with inflation. Furthermore, THESL expects to be in hiring mode for the next several years: the company needs to train replacement staff for its aging workforce.

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Intermediate Financial Risk Profile

Accounting

Toronto Hydro's Dec. 31, 2006, audited, consolidated financial statements were prepared in accordance with Canadian GAAP.

In its financial statements, the company presents the cash recovery of regulated assets as a cash inflow under investing activities in its cash flow statement and not as cash flow from operations. Furthermore, the company has identified a number of significant contingent liabilities arising from class action lawsuits against Toronto Hydro, but given the preliminary status of the actions, it is not possible at this time to quantify, if any, the financial impact of an adverse ruling.

In its analysis, Standard & Poor's treats the company's promissory note held by the City of Toronto as debt and has assigned no equity credit. Coupons on the notes are added to interest expense.

Financial policies and corporate governance comparable to those of peers

The company has operated with a commercially oriented independent board of directors since 1999, with only three city representatives on its 11-member board. The utility is unlikely to be sold or privatized in the foreseeable future.

Toronto Hydro's target leverage, as measured by total debt-to-total capital, is 60% and consistent with domestic peers. Regulatory directives that will include a 40% deemed common equity component for its regulated electricity network business by 2009, in line with all other Ontario LDCs, largely dictate the level of leverage on a consolidated basis. Previously, regulatory rate determinations were based on a 35% deemed common equity component.

Toronto Hydro's dividend policy, adopted in 2004, requires the utility to distribute the larger of 50% of its consolidated net income or C$25 million. The City relies on Toronto Hydro's board of directors to assess the company's ability to pay future dividends, including an assessment of the effect that any dividend payment might have on the company's financial profile and the credit ratings.

Cash flow insufficient to fully fund capital plans

Funds from operations (FFO) will likely remain between C$200 million-C$250 million in the period 2007-2009. THESL implemented a rate decrease in 2006. Furthermore, the company's withdrawal from the competitive electricity retail market as of Dec. 31, 2006, and the February 2006 sale of its water heater business meant the loss of related cash flow from operations. Toronto Hydro expects to replace a portion of those cash flows with cash generated from its street lighting business purchased from the City in 2006, and growth in its unregulated telecom and energy services activities.

Concurrently, we expect capital expenditures of as much as C$900 million in the 2007-2009 period compared with about C$500 million spent from 2004 to 2006. As a result, Toronto Hydro's internal funding ratio, as measured by net cash flow to capital expenditure, will fall well below its previous level of more than 100%, to the 50%-70% range for the next few years. Furthermore, we do not expect that the city will forgo dividend payments, which are typically in C$30 million-C$40 million range. Nevertheless, FFO will support part of the company's annual capital expenditure program, expected to be in the range of C$240 million-C$370 million per year and most of the forecast spending will serve to increase the regulated distribution rate base and future cash flows.

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The largely regulated nature of Toronto Hydro's earnings ensures an element of security and predictability of cash flows. Underlying cash flows from the business should generate average FFO interest and debt coverage of 3.5x-4.0x and 15%-17%, respectively. Much will depend on the actual approval and timing of the forecast capital spending plan.

Capital structure unlikely to change

We expect leverage to remain high, at about 60%. In its tariff determinations for THESL, the OEB imputes an equity layer of 40%. There is little financial incentive for the company to materially vary from this level, because any additional equity at the subsidiary level would generate a lower return (equal to the cost of debt) than the allowed ROE. Furthermore, covenants in the utility's trust indenture limit consolidated leverage to 75%.

The company's pension fund, included by the regulator in the cost of service determinations, was fully funded in fiscal 2006, limiting Toronto Hydro's contingent liabilities.

No interest rate of foreign exchange exposure

The nature of Toronto Hydro's debt limits the company's financial risk exposure. All long-term debt is at a fixed interest rate and upcoming maturities should be manageable. Any movement in interest rates, as the company partially debt finances upcoming capital expenditures and refinances its promissory note, does not present a material risk to the company. The OEB will generally allow THESL to recoup the market cost of debt. Furthermore, as all issues are in domestic currency, the company faces no meaningful foreign exchange exposure.

Financial flexibility comes from access to debt markets and modest discretionary spending

Toronto Hydro has adequate financial flexibility. The company does not have access to the equity capital market, nor is it likely to receive any material equity funding from its shareholder. The company's financial flexibility stems mainly from its ability to draw on significant debt financing, reduce or defer dividends of about C$30 million-C$40 million per year, and through the short term deferral of discretionary capital expenditures. Discretionary capital expenditure is in the C$30 million-C$40 million range per year. Potential cash saved from reduced dividend payments and deferred capital expenditure together represent 60%-70% of annual interest costs.

The demand for utility debt in the Canadian market is strong, and Toronto Hydro should not encounter difficulty accessing this market. The company has a capital market shelf program of C$1 billion that provides access to the debt markets. The shelf from which C$250 million was drawn in November 2007 will expire in February 2008 but will likely be renewed given that Toronto Hydro will need to approach the capital markets again in the next year or so to finance its above average capital spending program.

Table 1

Toronto Hydro Corp.--Peer Comparison*

Industry Sector: Electric Utilities--Canada

	--Average of past three fiscal years--			
(Mil. C$)	**Toronto Hydro Corp.**	**Hydro One Inc.**	**Hamilton Utilities Corp.**	**Hydro Ottawa Holding Inc.**
Rating as of Nov. 12, 2007	A-/Positive/--	A/Positive/A-1	A/Positive/--	A-/Positive/--
Revenues	2,361.9	4,371.3	499.4	441.1
Net income from continuing operations	92.9	478.7	12.5	12.7
Funds from operations (FFO)	232.6	1,246.7	33.6	34.3
Capital expenditures	165.8	719.2	24.6	44.5
Cash and investments	387.5	0.0	48.3	0.0

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Table 1

Toronto Hydro Corp.--Peer Comparison*(cont.)				
Debt	1,327.0	6,241.9	105.0	151.2
Preferred stock	0.0	323.0	0.0	0.0
Common equity	832.7	3,532.2	181.7	160.0
Total capital	2,159.8	10,097.1	309.4	311.3
Adjusted ratios				
EBIT interest coverage (x)	2.7	3.2	3.4	2.6
FFO interest coverage (x)	3.4	4.4	4.7	4.5
FFO/debt (%)	17.5	20.0	32.0	22.7
Discretionary cash flow/debt (%)	(0.1)	4.0	2.9	(1.9)
Net cash flow/capex (%)	107.4	131.3	82.3	76.9
Debt/total capital (%)	61.4	61.8	33.9	48.6
Return on common equity (%)	11.2	10.1	7.5	5.2
Common dividend payout ratio (unadjusted; %)	58.6	61.6	82.7	0.0

*Fully adjusted (including postretirement obligations).

Table 2

Toronto Hydro Corp.--Financial Summary*

Industry Sector: Electric Utilities--Canada

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2006**	**2005**	**2004**	**2003**	**2002**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Negative/--	A/Watch Neg/--
Revenues	2,247.0	2,612.6	2,226.0	2,498.5	2,440.7
Net income from continuing operations	90.2	92.4	96.1	99.5	46.9
Funds from operations (FFO)	253.7	226.0	218.0	250.2	188.2
Capital expenditures	188.4	197.2	111.9	112.5	130.6
Cash and investments	327.5	448.4	386.6	297.7	32.8
Debt	1,344.2	1,325.5	1,311.4	1,290.7	1,271.7
Common equity	871.1	819.3	807.8	752.4	661.8
Total capital	2,215.4	2,144.8	2,119.2	2,043.1	1,933.5
Adjusted ratios					
EBIT interest coverage (x)	2.6	2.7	2.8	2.8	1.8
FFO interest coverage (x)	3.7	3.3	3.2	3.6	3.3
FFO/debt (%)	18.9	17.0	16.6	19.4	14.8
Discretionary cash flow/debt (%)	(9.3)	4.6	4.5	19.7	(8.2)
Net cash flow/capex (%)	110.1	80.1	150.9	218.0	144.2
Debt/total capital (%)	60.7	61.8	61.9	63.2	65.8
Return on common equity (%)	10.4	11.1	12.2	14.1	7.3
Common dividend payout ratio (unadjusted; %)	51.2	73.6	51.2	5.0	0.0

*Fully adjusted (including postretirement obligations).

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Table 3

Reconciliation Of Toronto Hydro Corp. Reported Amounts With Standard & Poor's Adjusted Amounts*

	--Fiscal year ended Dec. 31, 2006--							
Toronto Hydro Corp. reported amounts (mil. C$)	**Debt**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	1,207.0	346.9	346.9	209.6	78.8	112.7	112.7	166.8
Standard & Poor's adjustments								
Operating leases	25.4	3.2	1.0	1.0	1.0	2.2	2.2	21.6
Postretirement benefit obligations	107.0	4.3	4.3	4.3	8.4	(4.4)	(4.4)	N/A
Asset retirement obligations	4.8	0.4	0.4	0.4	0.4	(1.5)	(1.5)	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	17.8	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	144.8	N/A
Total adjustments	137.3	7.9	5.7	23.5	9.8	(3.8)	141.0	21.6

Standard & Poor's adjusted amounts	**Debt**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	1,344.2	354.8	352.6	233.1	88.6	108.9	253.7	188.4

*Toronto Hydro Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. N/A--Not applicable.

Ratings Detail (As Of November 12, 2007)*

Toronto Hydro Corp.	
Corporate Credit Rating	A-/Positive/--
Senior Unsecured	
Local Currency	A-
Corporate Credit Ratings History	
26-Mar-2007	A-/Positive/--
20-Apr-2004	A-/Stable/--
25-Apr-2003	A-/Negative/--
13-Nov-2002	A/Watch Neg/--
Financial Risk Profile	Intermediate

*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.

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Pollution Probe Interrogatory #51

Ref: Ex. C2-T1-S1, page 70

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide a copy of the following report referenced in footnote 74 on page 70: S&P, *S&P Seeks Improved Risk-Assessment Metrics for U.S. Nuclear Power*, December 20, 2005.

Response

The report requested is attached.

Filed: 2008-04-08
EB-2007-0905
L-12-51
Attachment 1

STANDARD &POOR'S

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S&P Seeks Improved Risk-Assessment Metrics For U.S. Nuclear Power

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S&P Seeks Improved Risk-Assessment Metrics For U.S. Nuclear Power

For U.S. vertically integrated utilities and merchant energy companies that rely on nuclear generation, the sound operation of nuclear units can define their operational risk profiles and their ability to achieve projected financial results. Management's proficiency in overseeing a nuclear program and the integrity of nuclear operations are important elements in Standard & Poor's Ratings Services' credit ratings. Consequently, Standard & Poor's is engaged in an ongoing exercise to refine and enhance the analytical tools we use to help distinguish between subpar, average, and excellent nuclear operators as part of our credit evaluations. Standard & Poor's objective is not to predict an improbable catastrophic nuclear event. Rather, we seek to distinguish between those operators that have the potential to exhibit sound and stable financial performance because of robust operations and those whose nuclear operations are vulnerable to problems that may impair financial performance. Yet, we have found that our ability to differentiate among operators is limited by technical complexities associated with nuclear operations and industry practices that curb the disclosure of benchmarking and performance measures.

Nuclear Operations' Risks And Rewards

Nuclear dependence is important to credit quality because low variable costs associated with owned and contracted nuclear facilities benefit consumers and owners of vertically integrated utilities. For example, in its most recent annual statistical report, Southern California Edison Co., a vertically integrated utility, reported that its average per kilowatt-hour fuel cost for nuclear energy was less than 8% of the average per kilowatt-hour fuel cost for electricity derived from all of its resources (1). Such a contrast is not atypical. Nuclear output also creates the potential for merchant energy companies to earn profits because nuclear units possess relative advantages in markets where significantly more costly fuels set electricity prices, which is almost universally the case.

Although nuclear generation provides considerable advantages, it simultaneously presents latent risks to financial performance. During unplanned outages at nuclear units, nuclear operators frequently need to purchase meaningfully more costly replacement power to meet contractual commitments. Exposure to outages and their attendant costs is often exacerbated because nuclear outages tend to be lengthy relative to outages at other types of generation units given the complexity of nuclear reactors and the safety and regulatory issues that must be addressed before a nuclear unit is returned to service. Moreover, in the case of regulated utilities, the ability to recover replacement power costs from ratepayers could be frustrated were regulators to conclude that an outage was avoidable.

Assessing Relative Nuclear Risk Among Operators

Historically, Standard & Poor's has used lagging indicators, such as NRC assessments and capacity and availability factors, in the rating process to track management's oversight of nuclear resources and resulting operational performance. However, recent experience has shown that these measures are not sound indicators of future operating success or good predictors of the financial performance of a company that is dependent on nuclear energy.

To move toward a more predictive analysis of operations that differentiates between operators, a series of qualitative and quantitative measures needs to be tracked over time. However, the ability to implement this type of

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analysis is limited by technical complexities, a nuclear industry that closely protects its most informative benchmarks, and difficulties in differentiating between the capabilities of different management teams and the workplace environments they have created. Therefore, except for the weakest operators, the ability to make distinctions between operators to assess relative exposure to outages and degraded performance is extremely challenging.

Moreover, the nuclear industry as a whole is exposed to individual members' operational issues. Problems at one operator's plants tend to create heightened scrutiny for all operators, which typically translates into higher operational, maintenance, and capital spending throughout the industry. This was evidenced by the numerous vessel-head replacements that needed to be made at pressurized water reactors following the 2002 discovery of vessel-head degradation at FirstEnergy Corp.'s Davis Besse plant. Added costs may have implications for financial performance and credit ratings.

The reactor vessel-head void discovered at Davis Besse provides evidence of the complexity of nuclear operations, as well as management oversight considerations that are important to credit quality. Problems at Davis Besse went unaddressed for considerable time by both company officials and on-site regulators. A May 2005 U.S. Government Accountability Office (GAO) report highlighted the extent of the technical complexities in its finding that while "NRC inspectors were aware of indications of leaking tubes and corrosion [at Davis Besse], the inspectors did not recognize the importance of the indications." (2). The Davis Besse incident highlighted the need to reassess the frequency of inspections, the adequacy of industry inspection standards, and inspection methods.

Public Service Enterprise Group Inc. (PSEG) also provides an example of a company whose financial performance was affected by poor nuclear performance that was tied to lax stewardship of nuclear resources. FirstEnergy and PSEG incurred considerable expenses to rehabilitate nuclear facilities and also bore sizable replacement-power costs to meet commitments during the duration of outages and degraded performance.

Industry Practices Limit Risk-Assessment Tools

The nuclear generation community's tight control over the operational information that might help outsiders predict financial performance complicates credit analysis where there is a dependence on nuclear plants. Assessments performed by the industry-controlled Institute of Nuclear Power Operations (INPO) and the data gathered by the industry participants that make up the Electric Utility Cost Group (used to assess and benchmark the performance of its members) are treated as closely guarded propriety information. Standard & Poor's rating-agency status has enabled it to pierce this veil, but only to a limited extent.

In 2000, before Davis Besse, the NRC implemented an inspection program based on risk-adjusted thresholds that redefined the level and scope of inspections of facilities and processes. The NRC inspection program revisions of 2000 also gave rise to more frequent quarterly reporting. Nevertheless, the reporting has not been very instructive for a number of reasons. The NRC had been assigning and continues to assign "green" assessments to many operators, representing the highest level of performance, which erodes the usefulness of these assessments as a tool for distinguishing between average and excellent operators. Moreover, the interval between the discovery of problems and the issuance of NRC reports explaining its analysis of problems reduces the effectiveness of such reports.

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A Search For Improved Risk-Assessment Metrics

Standard & Poor's has been holding ongoing meetings with numerous chief nuclear officers in an attempt to identify nonpropriety measures that could be used to better differentiate between operators. A number of measures were cited, but many tend to be subjective. The consensus gleaned from these meetings is that a discrete set of measures of management's proficiency and predictors of operational success are elusive.

In recent years, a number of operators cited track records of sound or improving capacity and availability factors and a trend towards shorter planned outages as evidence of strong management of their nuclear programs. In some cases, however, improvements in these measures masked maintenance deferrals that ultimately led to problems that degraded nuclear operations and financial performance. Thus, while tracking a series of qualitative assessments and quantitative averages over a period of time may help provide a better understanding, ultimately, these measures are imprecise when used as predictive tools.

Focus on safety

Time and again, the NRC and the industry's chief nuclear officers have cited an operator's safety culture and management practices as critical qualitative determinants of sound operations. In 1989, the NRC issued a policy statement emphasizing the importance of a workplace environment that promotes safety. Nevertheless, problems persisted within the industry.

Over the years, the NRC revised its safety culture policy statements a number of times. The most recent update of August 2005 is nonbinding. Nevertheless, the policy statement implores operators to create an environment in which employees can raise safety concerns without fear of retribution. It is also important that front-line employees who are in the best position to flag vulnerabilities sense that their concerns will be addressed. Otherwise, frustration may arise, which could have a chilling effect on reporting. Although the August NRC paper suggests that operators benchmark themselves against others, the policy statement is thin on delineating benchmarking measures. Furthermore, the NRC confirms that "No single indicator is sufficient in itself to identify weaknesses in the [safety conscious work environment], nor are there absolute measurements that indicate an unhealthy environment." (3)

INPO scores, the extent of backlogged unaddressed employee concerns, and the status of training program certifications at each plant, provide a starting point for evaluating whether safety culture principles are present in the nuclear workplace. However, the best way to gain a true reading of the strength of a company's safety culture is to meet with plant operators and staff for significant blocks of time to discern whether they are in fact living by a safety culture credo or merely paying lip service to safety consciousness. Yet, within the context of a multifaceted rating assessment, there are practical limitations on the time that can be devoted to pursuing this inquiry with each operator.

Maintenance backlog lists as a key determinant

Another factor cited by operators as a predictor of the health of an operator's nuclear operations is the operator's corrective maintenance backlog list. A lengthy list can be indicative of maintenance deferrals. Yet, even the best operators' lists are typically comprised of hundreds of highly technical corrective items that are either mission-critical or discretionary. Operators have latitude in the categorization and prioritization of list items, which can mask the potential for the degradation of plant performance. Furthermore, discretionary remediation projects that are allowed to fester on a backlog list could ultimately lead to the degradation of a plant's performance, even if they were relatively innocuous when first listed. Because of variability in categorization and discretion in the use of

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these lists, their value as predictors of operational success is diminished. However, such lists can serve as tools for initiating discussions with management to better understand a company's approach to critical and preventive maintenance efforts.

Standard & Poor's Nuclear Risk-Assessment Tools

In light of the cited limitations and to expand its assessment of nuclear dependent companies' financial resilience to nuclear problems, Standard & Poor's asks energy companies and utilities that are meaningfully dependent on nuclear output to prepare sensitivity analyses that illustrate the potential impact of varying levels of nuclear outages and degradation of nuclear production on financial performance. The influence of replacement power costs on financial performance is a critical component of this analysis.

This type of analysis does not directly compensate for the barriers that exist to the identification of bright line metrics that might facilitate efficient and meaningful comparisons of entities that are dependent on nuclear output. Just the same, even though financial sensitivity analysis does not speak to the probability that a particular operator will achieve stable or volatile nuclear and financial performance, it still helps identify the magnitude of the contingent exposures facing nuclear dependent companies.

Standard & Poor's will continue to rely on those operational metrics that are available to it, such as capacity and availability factors, and will also endeavor to benchmark capital and operating expenditures over a refueling cycle in an effort to identify outliers. Some troubled operators will be readily segregated from more robust operators based on NRC watch listings, event reports, and enforcement actions. But, by and large, we expect that our ability to differentiate between operators as part of our assessments of nuclear exposure will continue to be colored by technical complexities and the veil that shrouds the nuclear industry. Therefore, for the foreseeable future, Standard & Poor's expects to continue to extend homogeneous treatment to most nuclear operators in its business risk assessments.

Notes

(1) Edison International, "2004 Financial and Statistical Report."

(2) U.S. Government Accountability Office, "Challenges Facing NRC in Effectively Carrying Out Its Mission, Testimony Before the Subcommittee on Clean Air, Climate Change, and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate, Nuclear Regulatory Commission," May 26, 2005.

(3) U.S. Nuclear Regulatory Commission, "NRC Regulatory Issue Summary 2005-18, Guidance For Establishing And Maintaining A Safety Conscious Work Environment," Aug. 22, 2005.

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Pollution Probe Interrogatory #52

Ref: Ex. C2-T1-S1 page 71

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane states on page 71:

"OPG faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities."

Please have OPG provide its record of outages along with an explanation of how this record compares with an appropriate industry benchmark?

Response

OPG Nuclear's outage performance over the period 2005 - 2007 is shown in Ex. E2-T1-S2 Appendix C. Appendix C records actual outages, duration, cause of outage and mitigation steps to minimize the reoccurrence of outage causal factors such as failures in the primary heat transport system and liquid zone controls.

OPG benchmarks outage duration using Unit Capability Factor ("UCF") which represents maximum unit generation output less all outages for the plant. Exhibit A1-T4-S3 Section 9.2 discusses nuclear facility performance against industry benchmarks, including UCF. The UFC (three year average) benchmarks show that the Darlington plant compares well against the CANDU top performers and the trend continues to improve - at the end of 2006 there were two Darlington reactors in the CANDU top quartile for UCF. The Pickering B reactors have not achieved similar status largely due to major (long duration) outages for fuel channel work and major one-time extraordinary events in 2007 (ref. Ex. E2-T1-S2 page 4 lines 20 – 30). The Pickering A reactors are also working through issues related to the material condition of the plant associated with a seven year shutdown of the units and the major one-time extraordinary events in 2007 (ref. Ex. E2-T1-S2 page 4 lines 20 - 30).

Pollution Probe Interrogatory #53

Ref: Ex. C2-T1-S1, page 77

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide copies of the following S&P reports referenced in footnotes 83 and 84 on page 77:

US is Looking at Paced Reemergence of the Nuclear Power Option, June 26, 2006 and *Time for a New Start for the U.S. Nuclear Energy?* June 4, 2003.

Response

Attached, please find,

1. S&P, *U.S. Is Looking at a Paced Reemergence of the Nuclear Power Option*, June 26, 2006

2. S&P, Time for a New Start for U.S. Nuclear Energy? June 4, 2003

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STANDARD &POOR'S RATINGSDIRECT

RESEARCH

U.S. Is Looking At A Paced Reemergence Of The Nuclear Power Option

Publication date: 26-Jun-2006
Primary Credit Analyst: Richard W Cortright, Jr., New York (1) 212-438-7665;
richard_cortright@standardandpoors.com

A sustained interest in adding new nuclear power plants to the U.S. electric generation fleet's resource mix has gained considerable momentum in the past year. The last nuclear plant was ordered more than 30 years ago, in 1973. But several influences have combined to generate a clear resurgence of interest in adding new nuclear capacity beyond the modest repowering efforts and 20-year license extensions of recent years. This interest ranges across an array of political and industrial constituents.

This is sparked in large measure by:

- Supportive federal and state legislation,
- Concern over the reliability and capacity of rail transportation infrastructure and carbon dioxide emissions related to coal, which fuels about 50% of the country's power generation,
- An increased dependence on natural gas (which fuels about 20%) and its volatile prices, and
- Appeal of operating economics.

Moreover, the country continues to need additional electric generating capacity simply to meet ever-increasing demand for power, which grows at a relatively steady 1.5% to 2% annual pace, and ratepayers are anxious to limit volatility in their electric bills, which is a direct consequence of a heavy dependence on gas.

The passage last August of the Energy Policy Act of 2005, among many other things, sought to reduce the cost and riskiness associated with nuclear investments. The act included a 1.8-cent per kilowatt-hour tax credit for 6,000 MW of new nuclear capacity, as well as standby support to offset the financial effect of construction delays due to regulatory lag or litigation. The act extended the Price-Anderson Act, which provides the framework for limiting operator liability associated with nuclear accidents, and it modified the tax treatment of certain nuclear decommissioning trusts, particularly those related to nonrate-based facilities.

Regional Factors Come Into Play

While there is no national consensus on the willingness to increase nuclear capacity, certain regions appear much more receptive than others, specifically, the Southeast and Midwest. Others, most notably the Northeast and the West Coast, remain generally opposed to the idea, despite the clear need for more base load resources.

Recognizing this, several states have already taken steps to ease the permitting and construction process. Florida passed its own energy legislation that enables utilities to recover their nuclear-related preconstruction and licensing costs. It also excludes nuclear plants from the state's competitive bidding rules related to new capacity. In South Dakota, the state legislature passed a bill that encourages research and development related to advanced design reactors and, and generally fosters consideration of the nuclear option for power generation. Several other states are considering similar bills.

Long Lead Times For Approval And Construction

Placing any plant into operation is a long-term proposition, with new facilities unlikely to enter service

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before 2015-2016, or about five years following receipt of all relevant permits. Recognizing the lead time necessary for approving and building a nuclear plant, several partnerships and consortia are moving forward today with preparing to file applications with the NRC for a combined construction and operating license (COL), in many cases for multiple units. The NRC has indicated that 16 utilities have noted serious interest in as many as 25 new facilities. For instance, Duke Energy Corp. and Southern Co. expect to submit COLs within the next year-and-a-half for one or two 1,000 MW units to be built in South Carolina.

Such a filing does not commit either company to actually construct the facilities, which is a decision they could make in several years depending on the prevailing market, political, and regulatory dynamics. Duke has estimated the total cost to put the two plants in service to be between $4 billion and $6 billion.

Perhaps the single greatest hurdle to licensing the next nuclear facility, and funding it, is public acceptance of the technology. There are two principal considerations in this regard: operational safety and waste disposal. On the operational front, nuclear plants have demonstrated a strong history since the mid-1990s of safety and operational performance. The performance of safety systems has achieved very high standards, and the absence of headline news and the reduction of forced outages have added to the relative comfort that the public has generally achieved with nuclear technology, until the threat of terrorism injected a whole new risk element into the equation. However, this last consideration does not appear to be deterring companies in the Southeast and Midwest.

Standard & Poor's Rating Services believes the waste issue will remain a very challenging political problem, but will not be sufficiently disruptive to prevent the licensing of new plants.

Financial Considerations Remain Daunting

From an investor's perspective, the legacy of the unpredictable and prolonged construction period of the last nuclear build cycle and the mixed operating performance of the industry until about 10 years ago remains graphically inked in a collective consciousness. The sheer amount of capital necessary to bring a new plant on line is daunting, so the design of capacity payment structures in 10 years will be a critical consideration. The price of natural gas 10 years hence is also a considerable uncertainty.

At the same time, we recognize that the federal government is initiating numerous structural changes designed to prevent a repeat of the extremely negative and financially ruinous experience of the last nuclear construction cycle, such as standardizing reactor designs, providing tax breaks and loan guarantees, and creating a combined construction and operating license, while the industry itself has demonstrated an ability to operate safely and efficiently in recent years.

So, while slow and steady, the return of the nuclear option has considerable momentum that is not likely to wane.

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RESEARCH

Return to Regular Format

Time for a New Start for U.S. Nuclear Energy?

Publication date: 04-Jun-2003
Credit Analyst: Peter Rigby, New York (1) 212-438-2085

Since its beginnings, commercial nuclear energy has offered the tantalizing promise of clean, reliable, secure, safe, and cheap energy for a modern world dependent upon electricity. No one did more than Lewis Strauss, chairman of the U.S. Atomic Energy Commission, to define expectations for the industry when he declared in 1954 that nuclear energy would one day be "too cheap to meter." But the record proved far different. Nuclear energy became the most expensive form of generating electricity and the most controversial following accidents at Three Mile Island and Chernobyl. And today's electricity industry's credit problems of too much debt and too many power plants will do little to invite new interest in an advanced design nuclear power plant. Yet energy bills circulating through the U.S. Senate and House of Representatives hope to change that perception and perhaps lower the credit risk sufficient enough to attract new capital. Will Washington, D.C.'s new energy initiatives lower the barriers to new nuclear construction? Many would like to think so, but it will be an uphill battle.

The House version of the Energy Bill modestly "…sets the stage for building new nuclear reactors by reauthorizing Price-Anderson…." Since 1957, the Price-Anderson Act has indemnified the private sector's liability if a major nuclear accident happens on the premise that no private insurance carriers could provide such coverage on commercial terms. Without Price-Anderson, it is difficult to envision how nuclear plants could operate commercially, now or in the future. The more ambitious Senate version of the Energy Bill seeks to jump-start new nuclear plants in the U.S. by providing measurable financial resources for new projects. According to the latest version of the Senate Energy Bill, the Secretary of Energy could provide financial assistance to supplement private sector financing if the proposed new nuclear plant contributes to energy security, fuel, or technology diversity or clean air attainment goals. The bill would limit financial assistance to 50% of the project costs with financial assistance being defined as a line of credit, secured loan, loan guarantee, purchase agreement, or some combination of these assistance plans.

Key Nuclear Energy Provisions to the Proposed Energy Bills

House Version (H.R. 6)

- Reauthorization of Price-Andersen Act
- Support Nuclear Energy Research

Senate Version (S. 14)

- Reauthorization of Price-Andersen Act
- Provide Financial Assistance to Finance Private Sector Nuclear Power Plants
- Support Research on Advanced Reactor Designs

In light of how well U.S. nuclear plants have generally been operating recently and with promising new technology on the horizon, nuclear energy would seem to have a future. Currently, about 20% of the nation's electricity comes from nuclear power plants (see chart below). The introduction of competition and deregulation in the U.S. has helped drive the nuclear fleet into achieving record availabilities and load factors, as independent owners have taken ownership from utilities that divested generation. Even utilities that did not divest their nuclear plants have experienced greatly improved performance across the board. Today's nuclear power plant

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operation and maintenance and fuel costs are remarkably low compared with many fossil fuel plants--as low as 1.68 cents per kWh according to the Nuclear Energy Institute. Although the high-profile accidents at Three Mile Island and Chernobyl greatly raised the threshold for safer operations, operating success stories may overstate what may be achievable with new designs. Nuclear operators in the U.S. have had a few decades to work out operational problems, and with original debt paid off, more cash resources have been dedicated to improving performance. Providers of new capital for advanced, nuclear energy will want some comfort that credit and operating risks are covered. But the industry's legacy of cost growth, technology problems, cumbersome political and regulatory oversight, and the newer risks brought about by competition and terrorism concerns may keep credit risk too high for even the Senate bill to overcome.

Historic Risks Will Persist

A nuclear power plant's life cycle exposes capital providers to four distinct periods of credit risk that history has shown will persist. These periods are pre-construction, construction, operations, and decommissioning (see chart below). The risks tend to be asymmetrical with an enormous downside bias against credit providers and little or no upside benefits. To attract new capital, future developers will have to demonstrate that the risks no longer exist or that the provisions of the Energy Bill can effectively mitigate the risks.

image

During a nuclear plant's pre-construction phase, lenders, as they do with other projects, face the risks of cost growth and delay. When nuclear engineers encountered technology problems during the planning stages in the 1960s and 1970s, solutions inevitably resulted in scope changes or re-designs, or both. A 1979 Rand Corp. study for the U.S. Dept. of Energy still serves as a warning to investors in new, untested nuclear technology. The study found that cost budget estimates grew on average 114% over first estimates and that final actual costs exceeded those estimates by 141%. Half of the plants in the study never reached commercial operations. An extreme example of delays and cost overruns, which remains fresh in investors' minds, is Long Island Lighting Co.'s Shoreham nuclear power station. Begun in 1965 at an initial cost estimate of $65 million-$75 million, Shoreham endured 20 years of construction delays and design changes due to legal battles, local opposition, regulatory and political intervention, and technical problems that pushed the final cost to almost $6 billion. In the end, a complete and fully licensed power plant never went operational, and ratepayers, investors, and taxpayers are still footing the bill. Another example is TXU Corp.'s 2,300 MW Comanche Peak Units 1 and 2, which took longer than any nuclear plant to build and saw costs mushroom to nearly $12 billion by the time full operations began in 1993.

That no new nuclear plant construction has begun in the U.S. for over 20 years suggests that a new one would be susceptible to cost growth risk, as engineers incorporate advances in control and power systems, fuel systems, safety and regulatory requirements (which could become more onerous during the years of design and construction), material sciences, and information technology. Even promising new designs, such as the pebble bed reactor (PBR) design that Eskom Holdings Ltd. of South Africa plans to build soon, would likely risk design changes and attendant cost growth if built in the U.S. Cost growth and delay can also arise from design and scope changes due to the efforts of effective interveners, such as the anti-nuclear citizen activist groups that successfully delayed Shoreham and ultimately prevented it from going commercial.

History also suggests that the construction and start-up phases of new nuclear power will likely encounter problems that will result in increased costs and delays. Licensing delays, construction management problems, procurement holdups, troubles with new technologies and construction defects, among other problems extended construction beyond 10 years for some U.S. nuclear power plants. It would be overly heroic to assume that the first nuclear plant to be built in more than two decades would escape the industry's legacy of construction problems. For a debt-financed construction endeavor, likely to cost hundreds of millions of dollars (possibly into the billion dollar plus range), these problems, or even the possibility of such problems, will likely drive risk-averse lenders to demand a significant risk premium unless a third party assumes completion and delay risks. In the world of cost-of-service,

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capacity to

rate-of-return environments, utilities could, and did, pass these costs on to ratepayers to a certain extent. The bankruptcies of El Paso Electric Co. and Public Service Company of New Hampshire in the 1980s, however, attest to the limits of ratepayers' capacity to absorb construction risk.

Today, no utility or independent power producer or their capital providers will want to take unmitigated construction risk, particularly if it is difficult to quantify. In addition, given the possibility that much of the construction risk of a new nuclear plant may lay outside of the engineering, procurement, and construction contractor's control, no contractor will want to risk its balance sheet to provide the fixed-price, date-certain, turnkey construction contracts that have given great certainty to the cost of today's new fossil-fueled power plants. Because of the long lead-time historically associated with nuclear power, securing 100% financing upfront, as the industry has become accustomed to, may be difficult. That could introduce financing risks if projects encounter problems during construction; delays in securing final financing would, among other problems, drive up capitalized interest costs during construction and ultimately the project's cost.

While U.S. nuclear power plants have operated without major mishap for over 20 years, unexpected costs during the operational phase of a nuclear plant can be substantial. And it is unclear whether and if proposed government programs will be able, or willing, to offset the risk of these costs. Still, today's operators have demonstrated that they can safely operate older nuclear power plants. Yet the potential that incidents, such as last year's wholly unanticipated corrosion problem at FirstEnergy Corp.'s Davis Besse 900 MW plant, are not unique, one-time affairs will keep credit risk high for nuclear plant owners. In addition, investors will remember that the Davis Besse repair costs of about $400 million, not including replacement power, are unrecoverable from ratepayers, leaving investors to shoulder the costs. Incidentally, had the outage occurred during a period of high power prices and tight supply, as was the case two years ago, the cost to investors would have been much higher.

Decommissioning costs, which entail the considerable expense of tearing down a plant and safely disposing or storing the radioactive waste, remain uncertain at best given how few U.S. nuclear plants have undergone decommissioning. Progress toward creating a permanent disposal site for nuclear waste at the government's Yucca Mountain site in Nevada will help mitigate decommissioning risk, as well as spent fuel disposal costs. Again, it is not clear who will bear decommissioning costs, but if lenders foresee any lender liability risk, they will steer clear of new nuclear investments or require steep compensation. That, as a point aside, may be one of the reasons so many plants have been granted license extensions. Refurbishing a depreciated nuclear power plant costs far less than decommissioning one.

Finally, for many of the reasons described above and all else being equal, Standard & Poor's Ratings Services has found that an electric utility with a nuclear exposure has weaker credit than one without and can expect to pay more on the margin for credit. Federal support of construction costs will do little to change that reality. Therefore, were a utility to embark on a new or expanded nuclear endeavor, Standard & Poor's would likely revisit its rating on the utility.

Competition Introduces New Risks for Nuclear Energy

As electricity deregulation and industry reform have progressed, capital providers to the nuclear power sector face some of the same risks as capital providers to other power generation technologies. Again, if policymakers want to attract capital to the industry, lenders in particular will likely have to be convinced that at least some of the risks are covered or mitigated. The sheer size of most new nuclear investments suggests that downside risk for lenders could be considerable indeed.

Clearly, buying and selling electricity in a competitive environment comes with its risks, both market and political. The wake of California's electricity reform problems forced one utility into bankruptcy and brought another to the brink of bankruptcy. Independent power producers are resisting efforts by California and its Department of Water Resources to abrogate or renegotiate recently executed power sales agreements. These events, combined with the credit crunch that has hit many other utilities and energy merchants, have understandably moved public utility commissioners and capital providers into more risk-averse postures. Absent these problems, nuclear power would still be challenged to attract new capital; in this environment, however, the task is all the more difficult. Competition has dramatically shifted risks from ratepayers to lenders and other investors; that is not likely to change.

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Exhibit I
Tab 3
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In a competitive wholesale power environment, nuclear plants would likely sell power as a base load generator behind hydroelectric and ahead of coal and gas. Capital costs would be higher than coal plants and much higher than natural gas plants, but marginal operating costs would be very low, as they are now. Nonetheless, an owner of a new nuclear plant would likely want a long-term--20 years or more--power contract with a creditworthy utility to ensure that fixed and variable costs are covered in order to attract the massive amount of capital needed for construction. Alternatively, a utility that wants to add a new nuclear plant to its portfolio would need regulatory assurances from its public utility commission that the entire cost of the plant would be recoverable from its rate base. In the first instance, few utilities, or their regulators, want such long-term contract obligations, especially in an environment of excess generation that can be purchased on the cheap. That gas costs and clean-air compliance costs could be on the rise might offset some of those concerns. For some of the same reasons, public utility commissioners may not be so forthcoming with their authority to grant rate-based treatment of a new nuclear plant, especially in the pre-construction period if cost growth risk remains uncovered. For many commissioners, the all-in costs of alternative generation will likely seem more predictable and cheaper than a new nuclear plant.

The current backlash against regulatory reform and open markets in parts of the country could also put a new nuclear plant at risk. A large, new nuclear plant will typically need access to a large electrical network with a geographically dispersed customer group--the network that a well-structured regional transmission organization, as envisioned by FERC, could provide. However, if transmission access is limited or if states have chosen to maintain barriers to electricity trading and marketing, physical or otherwise, as many have, a new nuclear power plant may find itself operating within a much smaller system, a situation that could raise its credit risk, all else being equal. One obvious mitigant to this risk would be to build much smaller nuclear plants, such as the 100-MW modular PBR designs.

Whether a new nuclear plant is financed directly from the wallets of captive ratepayers or with long-term contracts, a large nuclear plant's size relative to its market raises outage-cost risk. A nuclear plant with a long-term power contract will likely contain provisions to provide replacement power, or the financial equivalent, if the plant becomes temporarily unavailable. Given nuclear power's vulnerability to rare, but extended forced outages, replacement power costs for 1,000-2,000 MW of base load power could be considerable, which would factor into credit risk. Similarly, a utility that owns a large nuclear station could find itself spending hundreds of millions of dollars to cover its short position while its station was down without assurances of recovery from ratepayers. Again, smaller PBRs would mitigate this risk.

Some of the preliminary provisions of the Senate Energy Bill contemplate some of these risks. A long-term power contract, for example, with the federal government that covers 50% of the plant's costs might mitigate some of concerns of operating in a competitive environment. Similarly, loan guarantees or lines of credit could also offset the costs. However, if gas- and coal-fired plants can be built for much less (e.g., 50% less) and the operational risk of extended nuclear plant outages remains uncovered, a government program could fall short of relieving investors' credit concerns. Moreover, as with any government subsidy program, lenders would invariably factor U.S. government counterparty risk in the form of subsidy re-authorization uncertainty. Would the programs envisioned by the Senate bill last through the capital recovery period? Maybe. Maybe not.

A new risk for nuclear energy that has caught everyone's attention is terrorism. Because of the dangers that nuclear energy brings, security and insurance costs for nuclear facilities--new and old--are much higher than for fossil or renewable power plants. Therefore, in a competitive power environment, stakeholders in power generation may be reluctant to assume new risks that cost more to mitigate. Again, if a government subsidy can put security costs for new nuclear plants on an even playing field with conventional power generation, the industry could attract new capital. However, most new programs envisioned by Washington only address the construction risk.

As a note aside, some power generators and utilities may oppose efforts to support new U.S. nuclear generation capacity beyond existing subsidies, such as Price-Andersen, if they are heavily invested in coal and gas. New nuclear energy's low variable operating costs would likely displace existing coal-fired and gas-fired generation units in today's environment. It will do little, however, to displace oil-fired generation or lower U.S. oil imports because so little electricity, about 2% of the U.S. load, is actually generated by oil and much of that is for peak load, which nuclear energy would not serve anyway. But for stakeholders--investors, state politicians and regulators, lenders, customers--the risk that new nuclear generation could strand investment in conventional fossil-fuel-fired

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generation may be unacceptable unless the government provides financial compensation. And for a government trying to contain federal spending, those costs could be prohibitively expensive.

image

An Energy Bill Could Mitigate the Risks

To attract new capital to build the next generation of nuclear power plants in the U.S., developers will need to convince capital providers that the following risks are not materially greater than for fossil fuel power plants:

- The expense of cost growth, scope change, technology risk and start-up delay.
- The costs of unforeseen design problems that manifest themselves well after commercial operations begin.
- The costs resulting from the activities of effective interveners.
- The costs resulting from regulatory changes, including growth in oversight and compliance costs.
- The costs arising from forced outages in a competitive wholesale environment.
- The costs of replacing credit counterparties who are unwilling or unable to honor obligations or commitments upon which a nuclear plant's financing decisions were made.
- The added and uncertain expense of providing insurance and terrorism protection that nuclear plants need and that would disadvantage a nuclear plant operating in a competitive wholesale market.

The versions of the Energy Bill circulating around Capitol Hill may indeed mitigate enough of the risks that would otherwise dissuade investors from financing new nuclear capacity. The key drivers will be not so much in the broad generalities of the authorizing legislation, but in the details of the enabling regulations promulgated by the Department of Energy. That could take some time to draft. However, the Senate mark-up of the bill appears to recognize the issues. Absent an affordable alternative, if Price-Anderson is not re-authorized, existing nuclear power plants could be forced to close because of the potential liability of an accident that could run into the billions of dollars. Beyond Price-Anderson, however, considerable government financial support will likely be needed to attract capital, given the perceived credit risks.

The proposed Energy Act's subtitle section, the "Nuclear Energy Finance Act of 2003," provides support for "advanced reactor designs" that covers reactors that enhance safety, efficiency, proliferation resistance, or waste reduction compared with existing commercial nuclear reactors in the U.S. In addition, financial support would consider "eligible costs" that would cover costs incurred by a project developer to develop and construct a nuclear plant, including costs arising from regulatory and licensing delays. Financial assistance may take the form of a loan guarantee of principal and interest, a power purchase agreement, or some combination of both.

The government's proposed support of new nuclear construction will come with limits. The objective is to cover the risks of new nuclear generation technology and construction until capital providers gain confidence that a new generation of nuclear power plants is commercially sustainable. The act would limit support to 50% of eligible project costs and to the first 8,400 MW of new nuclear generation. The 50% limit would certainly control the government's exposure, as well as mitigate the risks of moral hazard that a complete guarantee would invite. However, as the industry has learned, some of the costs that could undermine new nuclear power are not those of construction and design, but are the operational ones that could arise after government assistance has ended. In addition, given the risk of cost growth and the likely high capital costs of a new nuclear plant, a 50% level of financial assistance may not be enough to entice a developer comparing uncertain estimates of $1,500-$2,000 per kW capital cost of a new generation nuclear plant with more certain $500 per kW combined-cycle gas turbine or $1,000 per kW coal plant capital costs.

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Whether or not the nuclear energy provisions of the Senate's version of the Energy Bill are good economic or energy policy is beyond the scope or intent of this article. New nuclear energy has compelling attributes, such as supporting energy diversity, replacing an aging U.S. nuclear fleet, offsetting rising natural gas prices, and reducing greenhouse gases and NOx, SOx, and particulate airborne pollutants. Once the capital costs are sunk, the variable operating costs can indeed be quite low. However, nuclear power tends to raise credit risk concerns during construction and well after construction. Investors, particularly lenders who rarely see any upside potential in cutting-edge technology investments, including energy, will likely find the potential downside credit risk of an advanced, nuclear power plant too much to bear unless a third party can cover some of the risks. An Energy Bill that covers advanced design nuclear plant construction risk may go a long way toward allaying those concerns, but if operational and decommissioning risks remain uncovered, look for lenders to sit this opportunity out.

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Pollution Probe Interrogatory #54

Ref: Ex. C2-T1-S1, page 80 and Schedule 26

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane expresses the "concern … that a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market". In footnote 86 she gives an example of Fortis as a Baa3 rated utility that experienced difficulties. In Schedule 26, Ms. McShane includes 6 additional companies that are rated below A by at least one bond rating agency: EPCOR, Newfoundland Power, Nova Scotia Power, Pacific Northern Gas Union Gas and Westcoast Energy.

Please provide all evidence/materials of which Ms. McShane is aware of regarding difficulties accessing financing experienced by any of these six additional companies with a rating of BBB.

Response

Ms. McShane is not aware of any specific financing issues that the referenced companies, other than Pacific Northern Gas, have faced. Pacific Northern Gas has experienced significant financing access issues. In the BCUC Decision In the Matter of Pacific Northern Gas Ltd., *Application for Approval to Recapitalize Under an Income Trust Ownership Structure* (September 9, 2005), the Commission cited the evidence of PNG, in which PNG stated "it has been unable to access sufficient third party debt to match its deemed capital structure. Instead, it has used retained earnings to replace third party debt (T4: 213; PNG 2005 RR, Exhibit B-3, BCUC IR 16.2), resulting in a capital structure comprising 51 percent common equity instead of 36 percent. PNG submits it has in the last few years pursued all avenues available to it in respect of obtaining debt financing, including approaching non-conventional lenders. Of these, only RoyNat Inc. ("RoyNat"), lastly in 2002, was willing to provide debt financing. The terms of the loan, however, are not typical for a regulated public utility, and include straight line amortization and a floating interest rate 300 basis points above Bankers' Acceptances."

With respect to the other companies listed, recent indicated spreads for new issues of long-term debt (as published by RBC capital markets) demonstrate that their cost of issuing new long-term debt can be materially higher than for A rated utilities.

The following table provides the most recent indicated yield spread over long-term Canada bond yields for a new 30-year bond issue for various utilities.

Utility	DBRS Debt Rating	S&P Debt Rating	Indicated Spread
CU Inc.	A (high)	A	157
Enbridge Gas	A	A-	170
Gaz Metro	A	A	172
Hydro One	A (high)	A	142
Terasen Gas	A	A	168
Toronto Hydro	A	A-	170
EPCOR Utilities	A (low)	BBB+	242
Nova Scotia Power	A (low)	BBB	205
Union Gas	A	BBB+	190
Westcoast Energy	A (low)	BBB+	190

Source: RBC Capital Markets, *MTN New Issue Indicative Spreads*, March 24, 2008.

Pollution Probe Interrogatory #55

Ref: Ex. C2-T1-S1, Sections IV. D and IV. E, pages 81 - 88

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

In light of her emphasis on the views of rating agencies, please have Ms. McShane explain if there exists any evidence to suggest that the views of these agencies could be subject to error.

Response

Yes, there have been circumstances in which the rating agencies have misestimated the risk of firms or securities; e.g., with respect to the recent sub-mortgage crisis, the rating agencies underestimated the risk of many mortgage-backed securities.

Pollution Probe Interrogatory #56

Ref: Ex. C2-T1-S1, Section IV. E, pages 85 - 88

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane refers to business risk profile scores from Standard & Poor's.

Please provide all of the evidence/materials that Ms. McShane is aware of that Standard & Poor's business risk ranking scale is an accurate measure of business risk.

Response

Ms. McShane is not aware of any studies that have been done to test the accuracy of the business risk ranking scale. Nevertheless, it provides an objective, third-party assessment of the relative risks of all utilities in the S&P universe. She is aware, however, that the business risk profile scores have been widely utilized by analysts to differentiate among utilities on the basis of relative business risk.

Pollution Probe Interrogatory #57

Ref: Ex. C2-T1-S1, page 104

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide a copy of *Pipelines/Gas & Electric Utilities*, by Karen Taylor of BMO Capital Markets, dated December 7, 2006.

Response

Please see response to L-12-9 (d) 14.

Pollution Probe Interrogatory #58

Ref: Ex. C2-T1-S1, page 192

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Ms. McShane states that her sample of vertically integrated utilities used to determine the incremental required return for a 45% equity ratio "has a median S&P debt rating of BBB".

Please explain why such a sample is appropriate for measuring incremental return in light of Ms. McShane's view on page 80 that "a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market."

Response

Ms. McShane would have relied on a sample of A rated utilities to estimate the incremental required return if she could have identified a large enough sample to assure reliability of the results. In the absence of such a sample, Ms. McShane relied on the market data that were available. Nevertheless, there is no inconsistency with estimating the incremental cost of capital for OPG using a sample with a lower debt rating, as long as the resulting proposed combination of financial parameters (ROE and capital structure) are consistent with the recommended target debt rating. Moreover, the reference at Ex. C2-T1-S1, page 80 was with specific respect to the Canadian debt market, whose public market for BBB rated debt is considerably smaller than that of the U.S.

Pollution Probe Interrogatory #59

Ref: Ex. C1-T1-S2, page 5, lines 5 - 7

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide the details of OPG's December 21, 2007 bond issue and of the calculation of the credit margin of 130 basis points.

Response

The chart below highlights the details of OPG's December 21, 2007 note issue (subscribed by Ontario Electricity Financial Corporation ("OEFC")) and the calculation of the 130 basis points.

Under the terms of the credit agreement with the OEFC the base rate on the note equals the yield for a benchmark Government of Canada bond with the same term as the note. In the event there are no benchmark Government of Canada bonds listed at the time with the same term, the rate is established by interpolating the terms of the two benchmark Government of Canada bonds that are closest to the term of the note, one being for a longer term and the other being for a shorter term. For the December 21, 2007 note issue the base rate was determined using the December 20, 2007 terms of the Canada 4 percent coupon bond due June 1, 2017 and the Canada 8 percent coupon bond due June 1, 2023. The interpolation resulted in a base rate of 4.01 percent for the December 21, 2007 note issue.

The credit spread is determined by the OEFC no later than on the close of business on the 4th business day before the note is issued. The credit spread is based on quotes from six Canadian banks, eliminating the highest and lowest and averaging the remaining four. Quotes are provided to OPG and the OEFC on a regular basis throughout the year by the same banks in order to track the trend in credit spreads based on changing market conditions. For the December 21, 2007 note issue the credit spread was established at 125 basis points, after the eliminating the quotes from National Bank Financial and Canadian Imperial Bank of Commerce. Identified separately, but included in the 130 basis point spread is a dealer commission fee of 5 basis points which is consistently charged by all of the 6 banks quoting credit spreads for OPG. Since the end of December 2007 OPG's credit spread has continued to increase, reflecting the general market volatility in financial markets, and is now approximately 160 basis points versus the 130 basis points at year end.

Interest Rate components on the $400M Note issued – Dec.21, 2007

	BMO	CIBC	NBF	RBC	SC	TD	Average
Benchmark Canada Bond Yield (10 yr)							4.01%
OPG Credit Spread to Go C Curve (bp)	112	139	100	127	127	135	125
Commission (bp)	5	5	5	5	5	5	5
All-in Spread to GoC Curve (bp)	117	144	105	132	132	140	130

All-in OPG Yield	5.312%

Canada Bonds Used to Interpolate			
Settlement :	20-Dec-07		
Coupon	Maturity	Yield	Price
4.00%	6/1/2017	4.003	99.98
8.00%	6/1/2023	4.089	144.47

Canada Curve Adjustment to Bond Maturity Date	
Interp to	Cad Yld
22-Sep-2017	4.01

Notes:
Benchmark Canada Bond Yield – Interpolated yield using the yields on the Canada 4% coupon due June 1, 2017 and the Canada 8% coupon due June 1, 2023, taken on December 20, 2007
OPG Credit Spread to the Government of Canada Bond is based on an average of the dealer bank quotes after eliminating the highest (CIBC) and lowest (NBF) quotes from the sample.
A commission of 5 bps is added to the credit spread to account for the issuance of debt on a commercial basis into the market place.

Pollution Probe Interrogatory #60

Ref: Ex. C1-T2-S1, Tables 2 - 6

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Please provide and explain the interest coverage ratios implied by the data in each of these tables reflecting actual equity ratios for 2005-7 and ratios recommended by Ms. McShane for 2008-9.

Response

The interest coverage ratio discussed by McShane in her evidence at Ex. C2-T1-S1, pages 86 and 87 references S&P and Moody's guidelines. These guidelines suggest that for an A rated entity, interest coverage (defined as FFO Interest Coverage) would range from 4.2 to 5.2 times for S&P and 3.5 to 6.0 times for Moody's. Comparable numbers for OPG based on the S&P methodology would result in interest coverage ratios of 4.2 and 5.0 for 2008 and 2009 respectively. OPG does not have a Moody's rating and therefore a comparable basis is not available.

Pollution Probe Interrogatory #61

Ref: Pollution Probe Interrogatories (Issues and References as Applicable)

Interrogatory

If OPG and its expert(s) (e.g. Ms. McShane) differ in their respective positions regarding responses to Pollution Probe's interrogatories, please identify and explain these differences. In addition, if OPG and its expert(s) have different/additional information (e.g. studies, references, evidence/materials, etc.) as requested by Pollution Probe's interrogatories, please identify and provide this different/additional information.

Response

OPG and its Cost of Capital expert, Ms McShane, do not differ in their respective positions regarding responses to Pollution Probe's interrogatories.