Q. Please provide copies of all equity reports and credit analyst reports supporting Ms. McShane's understanding of the change in the investment risk of the Canadian electric utility industry since NP's last rate order. Specifically, describe whether or not Ms. McShane believes the risk has increased, decreased or remained relatively constant since 2003.

A. Ms. McShane's testimony does not address changes in the investment risk of the electric utility industry in Canada since 2003. The electric utility industry in Canada is largely government-owned; there are only a handful of investor-owned electric utilities (FortisBC, AltaLink, ATCO Electric, FortisAlberta, Nova Scotia Power and Maritime Electric). Each company and jurisdiction is unique and the changes in the risk profile have been largely company-specific rather than industry-driven. The major business risk changes specific to individual utilities (either investor-owned or treated similarly to investor-owned utilities) of which Ms. McShane is aware are:

(1) the need for major capital investment in Alberta and Ontario, which could put downward pressure on the affected utilities' debt ratings as cited in the following DBRS reports:

- Attachment A, DBRS Hydro One June 2006
- Attachment B, DBRS AltaLink April 2007
- Attachment C, DBRS CU Inc. Jan 2007
- Attachment D, DBRS FortisAlberta May 2007

(2) a perception that the political risk in Ontario has declined, which is positive for the debt ratings of the affected utilities. An S&P report discussing the perceived decline in political risk, *Shining a Light on the Positive Outlooks for Ontario LDCs*, is Attachment E.

Other changes specific to individual utilities are: (1) new legislation in PEI in 2003 that returned Maritime Electric to traditional cost of service ratemaking and the approval of an energy cost recovery mechanism, both of which are risk-mitigating developments; and (2) the negotiated agreement and approval by the regulator in February 2007 for a process for the creation of an automatic fuel cost recovery mechanism for Nova Scotia Power, which would, if a mechanism is adopted, be positive for the company's business risk profile.

With respect to financial risk, the allowed capital structures of Canadian electric utilities have been relatively stable since 2003. The only major change has been in Ontario. In December 2006, the Ontario Energy Board adopted a single common equity ratio of 40% for all the electricity distributors, replacing a tiered approach which deemed common equity ratios of 35% to 50% based on the utilities' relative size (i.e., the smallest utilities were allowed the highest common equity ratios and vice versa). In August 2007, the OEB approved a common equity ratio of 40% for Hydro One's transmission business, in place of the previously approved 36% common/4% preferred share capital structure.

EBIT Interest coverage for the industry as a whole has effectively remained unchanged between 2002 and 2006 as indicated in Attachment F.

On balance, there has been no significant change in the level of investment risk of the Canadian electric utility industry since 2003.

DBRS Hydro One
June 2006

Hydro One Inc.

Report Date: June 30, 2006
Press Released: June 23, 2006
Previous Report: February 4, 2005

Matthew Kolodzie, CFA/Nick Dinkha, CFA
416-593-5577 x2296/x2314
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (middle)	Stable	Upgraded	Commercial Paper
A (high)	Stable	Upgraded	Senior Unsecured Debentures

(All figures in Canadian dollars, unless otherwise noted.)

RATING HISTORY

	Current	2005	2004	2003	2002	2001	2000
Commercial Paper	R-1 (middle)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures	A (high)	A	A	A	A	A	A

RATING UPDATE

On June 23, 2006, Dominion Bond Rating Service ("DBRS") upgraded the rating on the Senior Unsecured Debentures of Hydro One Inc. ("Hydro One" or the "Company") to A (high) with a Stable trend from "A" with a Positive trend, and upgraded the rating on Hydro One's Commercial Paper to R-1 (middle) from R-1 (low), also with a Stable trend. Key factors supporting the upgrade include: (1) improvements to the regulatory framework in Ontario in recent years; (2) the supportive political environment for the electricity industry; and (3) the expectation that Hydro One's financial profile, which has seen material improvement since 2002, will remain strong over the medium to longer term.

The regulatory framework in Ontario has stabilized over the past two years, and recent decisions by the Ontario Energy Board ("OEB") have been supportive of Hydro One's regulated operations. For example, in its latest decision on Hydro One's transmission operations (February 21, 2006), the OEB stated that it is mindful of the fact that heavy handed regulation is not good for investor confidence. This is an important consideration at a time when Hydro One will experience increased capital investment requirements to address transmission system constraints that have been identified by the Independent Electricity System Operator ("IESO"). In addition, for the first time since 1999, Hydro One's distribution rate base has been adjusted to reflect investments made over the past five years. While there is a level of uncertainty regarding the rate setting process beyond 2006, DBRS is of the view that the OEB will continue to be supportive and allow for full cost of service recovery and the ability to earn a fair market-based rate of return. DBRS is of the view that the current government is unlikely to interfere with the ratemaking process for regulated transmission and distribution operators as it has made a strong commitment to ensuring that ratepayers pay the full cost of electricity production and supply.

The key challenge for Hydro One will be managing potentially over $2.0 billion in transmission upgrades and conservation and demand management initiatives (i.e., smart meters) over the next five years. Cash flow from operations is expected to remain near $900 million annually over the next few years, but will be insufficient to fully fund capital expenditures and dividends. The annual shortfall will be funded with debt. Despite the cash flow shortfall, total adjusted debt-to-capital is expected to remain around 55% over the medium term as Hydro One's equity will experience modest growth through retained earnings. (Continued on page 2.)

RATING CONSIDERATIONS

Strengths:

- Involved primarily in regulated activities
- Attractive Ontario-based business franchise
- Strong and supportive shareholder – Province of Ontario

Challenges:

- Regulatory risk/risk of political intervention
- Low regulatory returns
- Lack of access to equity markets

FINANCIAL INFORMATION

	12 mos.	For the year ended December 30				
	Mar. 31, 2006	2005	2004	2003	2002	2001
Fixed-charges coverage (times)	3.07	3.05	2.92	2.75	2.33	2.44
Adjusted total debt-to-capital	54.0%	52.4%	54.1%	54.9%	56.4%	56.1%
Cash flow-to-adjusted total debt	17.7%	18.4%	17.5%	16.6%	13.8%	14.1%
Cash flow/capital expenditures (times)	1.34	1.37	1.27	1.43	1.27	1.25
Net income ($ millions) (adj. for non-recurring, after pfd.)	486	465	412	378	341	356
Cash flow from operations ($ millions)	962	946	920	855	725	708
Approved ROE	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed common equity in capital structure	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%

THE COMPANY

Hydro One Inc., one of the successor companies of the former Ontario Hydro, holds and operates electricity transmission and distribution assets, as well as a fibre-optic network across most of Ontario. Hydro One is the largest transmission operator in Ontario (servicing 95% of the province's transmission throughput), is the second largest electricity distributor in Ontario based on distribution throughput, and is the largest based on the number of customers. The Company is wholly owned by the Province of Ontario (the "Province"), although the Province does not guarantee debt issued by Hydro One.

AUTHORIZED COMMERCIAL PAPER AMOUNT

Program limit is Cdn$750 million (authorized limit remains Cdn$1 billion).

Rating Update Continued

Fixed charges coverage is expected to remain in the 2.75 times to 3.00 times range and cash flow-to-adjusted total debt is expected to be in the 16% to 18% range. As such, Hydro One's financial profile is expected to remain adequate to support an A (high) rating over the medium to longer term, given the Company's stable regulated transmission and distribution (T&D) operations in Ontario and barring any unforeseen negative changes to the regulatory framework, or political agendas. DBRS notes that a recent draft proposal by OEB staff to reduce the allowed ROE on distribution operations to below 9.0% would erode Hydro One's expected financial profile should this recommendation be ultimately adopted in future OEB decisions. However, impact on Hydro One's credit metrics cannot be assessed until the OEB's consultation process is complete and a final decision is made.

Regulation

Hydro One's electricity distribution and transmission subsidiary (Hydro One Networks) is regulated by the OEB under the *Electricity Act*, 1998 (the "Electricity Act"), with 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.

Hydro One's deemed capital structure is 36% common equity, 4% preferred equity, and 60% debt. Revenues from distribution operations are based on a fixed service charge and a volumetric charge, whereas revenues from transmission operations are based on peak monthly demand. The following is a summary of the regulatory framework for Hydro One's transmission and distribution operations.

Transmission:

On February 21, 2006, the OEB released its latest decision on Hydro One's transmission operations. This rate decision did not address any change in transmission rates, in fact transmission rates are still based on Hydro One's 2000 revenue requirements for transmission. The purpose of this rate decision was to deal with what the OEB had viewed as over-earnings by Hydro One's transmission operations. This has been achieved through the establishment of an earnings sharing mechanism, which will remain in place until transmission rates are addressed with a full rate hearing, likely some time in 2007. Key highlights of this latest decision are:

- The allowed ROE of 9.88% for transmission operations will remain in place until a new rate is established, likely in 2007.
- Any excess earnings, above an ROE of 9.88%, will be shared 50/50 with customers.

Distribution:

On November 11, 2005, the OEB set the allowable ROE for all Ontario local distribution companies (LDCs) at 9.00% (down from 9.88% in 2005).

On April 12, 2006, the OEB issued its rate decision on Hydro One's 2006 distribution rate application, with new distribution rates becoming effective on May 1, 2006. Hydro One elected to use the 2006 test year in its 2006 distribution rate application. The following are highlights of this rate decision:

- An approved rate base for distribution operations of $3,711 million. This represents the first rate base increase since the Electricity Act was implemented, which was set based on Hydro One's 1999 distribution rate base of $2,637 million.
- An approved debt rate of 6.24% on long-term debt and 3.33% on short-term debt, equivalent to a blended debt rate of 5.93% (53.7% of Hydro One's deemed capital structure for distribution is comprised of long-term debt and 6.3% is comprised of unfunded short-term debt).
- A $0.30 per residential customer per month as a result of the OEB's generic decision on Smart Metering.
- The total approved revenue requirement for Hydro One's distribution operations is $965 million, an overall increase of $130 million from the previously approved revenue requirement.
- The OEB disallowed Hydro One's proposal to harmonize distribution rates amongst all its customers, including LDCs the Company acquired in 2001.

Generic Cost of Capital (Distribution):

- On April 27, 2006, the OEB indicated its intent to establish a multi-year electricity distribution rate-setting plan for all LDCs in Ontario, which will include:
  - A generic cost of capital to be used in adjusting annual revenue requirements for 2007 and beyond, and
  - A mechanistic incentive rate adjustment for the period.
- The initial term of the multi-year plan will be three years, beginning with the 2007 rate adjustment.
- On June 19, 2006, the OEB posted on its website a draft report of Board staff containing staff's initial proposals for both the cost of capital and the second generation incentive regulation mechanism. The OEB intends to issue a second draft on July 20, 2006.
- DBRS notes that Hydro One's recent ratings upgrade is premised on the Company's reduced business risk profile associated with improvements to the regulatory framework and the supportive political environment that has materialized in recent years, together with improved credit metrics. In its draft report, Board staff has recommended an allowed ROE range of well below 9.0% for distribution operations (in the range of 7.52% to 8.36%), which would have a material negative impact on cash flow-to-debt and interest coverage ratios for Hydro One, especially if the same ROE range subsequently gets adopted for transmission operations.

However, it is too early to determine the impact on credit metrics until the consultation and review process is completed and a final decision is made. Furthermore, DBRS notes that due to past government intervention in the regulatory process, Hydro One's distribution operations earned well below the previous 9.88% ROE.

RATING CONSIDERATIONS

Strengths: (1) Almost all of Hydro One's assets and earnings are in regulated electricity T&D operations. Despite political interference in the Ontario electricity sector in the past, the current regulatory framework is supportive of Hydro One's T&D operations and is expected to remain supportive over the near to medium term. As such, T&D operations are expected to continue to provide a high degree of stability to Hydro One's earnings and financial profile. DBRS highlights a statement in Hydro One's most recent transmission decision, whereby the OEB indicated that in formulating its rate decision it was mindful not to diminish investor confidence in the utility by heavy handed regulatory actions. This is an important consideration, given the investment that Hydro One will have to make in upgrading the Ontario transmission grid over the coming years.

(2) Hydro One's transmission franchise area is one of the strongest in Canada, given that it covers virtually all of Ontario. While the Company's distribution franchise is less attractive, as it includes a large geographic area (most of rural Ontario outside major urban centres) with a low population density/high cost of service, the acquisition of 88 municipal electric utilities in 2001 has reduced unit costs and the regulatory framework provides full cost of service recovery with a market-based rate of return.

(3) While Hydro One faced a high degree of political interference during the previous government's mandate, the Province of Ontario (currently rated AA with a Stable trend by DBRS) continues to be a strong and supportive shareholder to the Company. The Province's support has been demonstrated in the past by various actions, including the provision of a line of a credit in 2002 when Hydro One was unable to access the capital markets. DBRS notes, however, that the rating on Hydro One is a stand-alone rating and is not guaranteed by the Province.

Challenges: (1) The key challenge facing Hydro One is regulatory risk and the risk of political intervention. Regulatory risk is an inherent challenge for any regulated utility given that the regulatory framework essentially dictates the maximum profitability that can be achieved and the degree of protection to bondholders. While some uncertainty exists regarding the regulatory framework beyond 2006, DBRS expects the OEB to remain supportive by continuing to allow full cost of service recovery with a market-based rate of return on regulated T&D operations. The key risk with respect to political intervention would be the imposition of a rate freeze, as was seen in 2002, which was at a time of high electricity prices and near a provincial election. However, DBRS believes the risk of political intervention in the rate-setting process is relatively low under the current provincial government's tenure, as this government has made a strong commitment to passing along the full cost of power to electricity ratepayers.

(2) The ROE of 9.0% for Ontario electricity distribution and 9.88% for electricity transmission is low in comparison with similar regulated utilities in the U.S., which are typically in the 10% to 12% range. As such, cash flow and coverage ratios for regulated utilities in Ontario will typically be lower than for similarly regulated utilities in the United Staes. However, the regulated rates of return for Ontario utilities are currently in line with the lower rates of return typically granted to regulated utilities in Canada. DBRS notes, however, that the Board staff recommendation of an ROE in the range of 7.52% to 8.36% will be lower than any other jurisdiction in Canada, placing additional pressure on credit metrics. Furthermore, there is a risk that lower ROEs for regulated utilities in Canada may make access to capital more challenging in the future, given that foreign content limits for investors have been eliminated by the Canadian government.

(3) Hydro One does not have access to the equity capital markets, as it is 100%-owned by the Province of Ontario. This limits the Company's financial flexibility, especially given its significant capital development commitments with respect to improving the reliability of the transmission grid. However, given the support of the provincial government, DBRS would expect Hydro One to reduce its dividends to the Province in order to support its equity base.

EARNINGS AND OUTLOOK

Income Statement ($ millions)	12 mos. ended March 30, 2006	For the year ended December 31 (1) 2005	2004	2003	2002	2001
Net revenues	2,271	2,285	2,189	2,186	2,173	2,199
EBITDA	1,473	1,493	1,418	1,391	1,366	1,375
EBIT	990	1,006	938	937	955	991
Gross interest expense	296	303	294	315	381	378
Net income (adjusted for non-recurring items, before prefs.)	504	483	430	396	359	374
Net income (after preferred dividends)	486	465	480	378	326	356
Return on average common equity (before non-recurring)	11.1%	10.8%	11.8%	9.7%	8.7%	9.7%

Segmented Information ($ millions)	%	12 mos. ended March 30, 2006	For the year ended December 3 2005	2004	2003	2002	2001
Net revenues:							
Transmission	56%	1,280	1,310	1,262	1,298	1,317	1,259
Distribution	43%	969	954	910	862	824	893
Other	1%	22	21	17	26	32	47
Total net revenues		2,271	2,285	2,189	2,186	2,173	2,199
Earnings before interest and taxes:							
Transmission		680	711	665	688	741	686
Distribution		319	305	284	252	263	339
Other		(9)	(10)	(11)	(3)	(49)	(34)
Total EBIT		990	1,006	938	937	955	991
Transmission throughputs (TWh)		n/a	157.0	153.4	151.7	153.2	146.9
Distribution throughputs (TWh)		29.3	29.7	28.5	27.9	27.1	21.3

n/a = not applicable.

Summary:

- The increase in EBIT in 2005 was largely a result of: Higher transmission revenues due to higher monthly peak demand in 2005 resulting from an abnormally hot summer, and
  - Earnings from distribution operations that were also positively impacted by weather as well as the collection of various regulatory deferrals.
- In general, EBIT has remained relatively stable over the past five years, in the $935 million to $1 billion range, which is reflective of the company's regulated operations.
- Interest expense has remained largely unchanged over the past three years, reflective of the Company's relatively stable debt levels.

Outlook:

- EBIT is expected to drop to near the $900 million range for 2006, under a more normal weather scenario (versus the more extreme weather experienced in 2005), and grow at a modest pace along with growth in rate base.
  - Also contributing to the lower EBIT is higher OM&A, resulting from an increase in pension contributions and increased spending on reliability-related maintenance.
- Furthermore, the earnings sharing mechanism for transmission operations will have a modestly negative impact on earnings in comparison to previous years.
- Earnings from one year to the next will continue to be sensitive to changes in monthly peak demand for electricity given the current regulatory framework for transmission.
- While there is a level of uncertainty regarding the rate setting process beyond 2006, DBRS is of the view that the OEB will continue to be supportive and allow for full cost of service recovery and the ability to earn a fair market-based rate of return.

FINANCIAL PROFILE

Statement of Cash Flow	12 mos. ended	For the year ended December 31				
($ millions)	March 31, 2006	2005	2004	2003	2002	2001
Net income adjusted for non-recurring items, after pfd.	486	465	412	378	341	356
Depreciation & amortization	446	446	446	417	384	352
Amortization of debt re-couponing	55	59	62	60	-	-
Other recurring non-cash items	(25)	(24)	-	-	-	-
Cash Flow From Operations	962	946	920	855	725	708
Capital expenditures	(719)	(691)	(727)	(597)	(570)	(566)
Common dividends	(343)	(273)	(247)	(226)	(174)	(240)
Free Cash Flow Before Working Capital Changes	(100)	(18)	(54)	32	(19)	(98)
Change in working capital	88	194	(33)	138	(199)	188
Net Free Cash Flow	(12)	176	(87)	170	(218)	90
Other investments/acquisitions/disposition	9	9	19	3	27	(447)
Other non-recurring adjust., incl. retail settlement variance	2	2	6	21	(52)	-
Net debt financing	121	(188)	83	(184)	232	357
Net equity/other financing	1	1	7	(12)	-	-
Net change in cash	121	0	28	(2)	(11)	0
Fixed charges coverage (times)	3.07	3.05	2.92	2.75	2.33	2.44
Adjusted debt-to-capital*	54.0%	52.4%	54.1%	54.9%	56.4%	56.1%
Cash flow/adjusted total debt (times)*	17.7%	18.4%	17.5%	16.6%	13.8%	14.1%
Cash flow/capital expenditures (times)	1.34	1.37	1.27	1.43	1.27	1.25

*Adjusted for equity treatment of preferred shares.

Summary:

- Cash flow from operations improved modestly in 2005 and for the 12-months ended March 31, 2006, but remained insufficient to fully fund capital expenditure requirements and dividends.
- However, a significant positive change in working capital funded the shortfall in 2006, as well as $188 million in net debt repayment.
- Cash flow-to-debt and interest coverage ratios have continued to improve over the past few years, and are well within the range of an A (high) T&D utility with a supportive regulatory framework.

Outlook:

- Cash flow from operations is expected to remain near $900 million annually over the next few years, but will remain insufficient to fully fund capital expenditures and dividends. The shortfall is expected to be funded with debt.
  - Annual capital expenditures (maintenance and upgrades) are expected to be in the $750 million to $800 million range as Hydro One continues to focus on transmission upgrades to mitigate critical system constraints, and
  - Dividends will likely be in the $250 million to $275 million range.
- Despite the cash flow shortfall, total adjusted debt-to-capital is expected to remain around 55% over the medium term as Hydro One's equity will experience modest growth through retained earnings.
- Fixed charges coverage is expected to remain in the 2.75 times to 3.00 times range and cash flow-to-adjusted total debt is expected to remain in the 16% to 18% range.
- As such, Hydro One's financial profile is expected to remain adequate to continue to support the A (high) rating over the medium term, given the Company's stable regulated T&D operations in Ontario.

LONG-TERM DEBT MATURITIES AND BANK LINES

As of June 30, 2006

	2006	2007	2008	2009	2010	2011-2015	2016 & thereafter	Total
$ (millions)	141	395	500	400	400	850	2,500	5,185
Avg. coupon	4.2%	4.4%	4.0%	4.0%	7.2%	6.0%	6.6%	5.6%

Long-Term Debt:

- Hydro One currently has available $1.95 billion on its $2.5 billion MTN Shelf, which was established in June 2005. The majority of funds received from the issuance of MTNs under its Shelf have been used to refinance maturing debt.
- Hydro One faces a manageable level of term debt maturities over the next five years. Maturities will likely be refinanced with debt issued under the above-noted Shelf.

Bank Lines and Commercial Paper:

- In August 2004, Hydro One reduced its syndicated committed bank lines to $750 million from $1 billion and, consequently, reduced the limit on its commercial paper program to $750 million.
  - However, the authorized Board limit on its commercial paper program remains $1 billion.
  - Hydro One has a $750 million committed 364-day revolving credit facility, maturing in August 2006. DBRS expects this to be extended.
- As at March 31, 2006, Hydro One had $40 million of commercial paper outstanding.

Hydro One Inc.

Balance Sheet
($ millions)

		As at December 31				As at December 31	
Assets	Mar. 31, 2006	2005	2004	**Liabilities & Equity**	Mar. 31, 2006	2005	2004
Cash + short-term investments	119	-	-	Short-term debt	10	9	49
Accounts receivable	724	622	707	L.t. debt due one year	589	589	539
Material and supplies	62	56	47	A/P + accr'ds	691	743	674
Current Assets	905	678	754	**Current Liabilities**	1,290	1,341	1,262
Net fixed assets	10,197	10,116	9,813	Long-term debt	4,778	4,466	4,613
Post-employment benefits	433	449	534	Post-employ. benefits	739	716	654
Def'd debt costs + long-term rec.	35	43	48	L.t. pay. + other liab.	613	610	672
Regulatory asset	426	430	443	Preferred shares	323	323	323
Goodwill	133	133	133	Shareholders' equity	4,386	4,393	4,201
Total	12,129	11,849	11,725	**Total**	12,129	11,849	11,725

Ratio Analysis	12 mos.	For the year ended December 31						
Liquidity Ratios	Mar. 31, 2006	2005	2004	2003	2002	2001	2000	1999
Current ratio	0.70	0.51	0.60	0.55	0.37	0.37	0.55	0.58
Acc. depreciation/gross fixed assets	36.7%	36.5%	35.8%	35.3%	34.5%	33.6%	32.5%	31.5%
Cash flow/total debt (1)	17.9%	18.7%	17.7%	16.9%	13.9%	14.3%	14.9%	15.1%
Cash flow/adj. total debt (1)	17.7%	18.4%	17.5%	16.6%	13.8%	14.1%	14.7%	15.1%
Adj. total debt/EBITDA	3.69	3.44	3.71	3.69	3.86	3.65	3.65	3.62
Cash flow/capital expenditures	1.34	1.37	1.27	1.43	1.27	1.25	1.54	1.39
Cash flow-dividends/capital expenditures	0.86	0.97	0.93	1.05	0.97	0.83	0.71	1.39
Total debt-to-capital (1)	53.3%	51.8%	53.5%	54.2%	55.7%	55.4%	53.5%	54.6%
Total adjusted debt-to-capital (1)	54.0%	52.4%	54.1%	54.9%	56.4%	56.1%	54.2%	54.6%
Average coupon on long-term debt	5.62%	5.61%	5.60%	5.50%	7.60%	8.05%	8.13%	7.70%
Hybrids/common equity	7.4%	7.4%	7.7%	8.1%	8.5%	8.8%	8.8%	0.0%
Deemed common equity	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
Common dividend payout (before extras.)	70.6%	58.7%	60.0%	59.8%	51.0%	67.4%	58.7%	38.6%
Coverage Ratios (2)								
EBIT interest coverage	3.36	3.34	3.20	3.00	2.51	2.63	2.50	2.45
EBITDA interest coverage	4.99	4.94	4.83	4.44	3.59	3.65	3.42	3.29
Fixed-charges coverage	3.07	3.05	2.92	2.75	2.33	2.44	2.30	2.32
Earnings Quality/Operating Efficiencies & Statistics								
Operating margin	43.6%	44.0%	42.9%	42.9%	43.9%	45.1%	43.5%	45.6%
Net margin (before extras., after pfd.)	21.4%	20.4%	18.8%	17.3%	15.7%	16.2%	17.0%	18.7%
Return on avg. common equity (before extras.)	11.1%	10.8%	10.1%	9.7%	9.1%	9.7%	9.4%	12.7%
Approved ROE	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.35%
Rate base - transmission ($ millions)	5,718	5,718	5,718	5,718	5,718	5,718	5,718	5,638
Rate base - distribution ($ millions)	2,637	2,637	2,637	2,637	2,637	2,637	2,445	2,467
Distribution lines (km)	n/a	122,118	121,736	121,285	120,767	120,448	113,880	113,400
Transmission lines (km)	n/a	28,547	28,643	28,621	28,492	28,387	28,490	28,889
Transmission throughputs (TWh)	n/a	157.0	153.4	151.7	153.2	146.9	146.9	144.1
Distribution throughputs (TWh)	29.3	29.7	28.5	27.9	27.1	21.3	17.6	18.1

(1) Adjusted for equity treatment of preferred shares.

(2) EBIT includes interest income; interest expense is gross interest expense.

n/a = not applicable.

DBRS AltaLink 2007

Report Date: April 30, 2007
Press Released: April 9, 2007
Previous Report: November 7, 2005

Eric Eng/Andrew Shannon
+1 416 597 7578/+1 416 597 7367
eeng@dbrs.com/ashannon@dbrs.comm

AltaLink, L.P.

Rating

Debt Rated	Rating Action	Rating	Trend
Commercial Paper	Confirmed	R-1 (low)	Stable
Senior Secured Bonds and Medium-Term Notes (Secured)	Confirmed	A	Stable

Rating History	Current	2006	2005	2004	2003	2002
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	NR	NR	NR
Senior Secured Bonds	A	A	A	A	A (high)	NR

Rating Update

DBRS has confirmed the ratings of AltaLink, L.P.'s (ALP or the Partnership) Senior Secured Bonds and Medium-Term Notes (Secured) at "A" and its commercial paper at R-1 (low). The trends remain Stable. The rating confirmation reflects the Partnership's continued solid financial profile, which is supported by a robust balance sheet, reasonable credit metrics and a supportive regulatory environment in Alberta that underpins the current ratings.

Over the past two years, ALP has undertaken a substantial expenditure program on system upgrades and new transmission projects assigned to the Partnership to meet growing demand in Alberta. This trend is expected to continue over the next few years, as ALP executes several major projects that have been assigned by the Alberta Electric System Operator (AESO). They include a $495 million North-South project that would be the largest ever in the province and is currently awaiting regulatory approval. As a result, significant free cash flow deficits are expected to continue and will place pressure on the balance sheet and financial metrics, as the invested capital is not included in the rate base until the completion of the projects. Therefore, timely project completion within budget is important to maintain the Partnership's financial health. (Continued on page 2.)

Rating Considerations

Strengths

- Low risk, regulated transmission business
- Strong franchise/strong economy in Alberta
- Strong financial profile
- Reasonable regulatory environment

Challenges

- Substantial capital expenditure program
- Significant external financing required
- Approved ROE sensitive to long-term interest rate

Financial Information

AltaLink, L.P. (CAD millions)	For 12 months ended Dec. 2006	Dec. 2005	Dec. 2004*	Apr. 2004	Apr. 2003
EBIT interest coverage (times) (1)	1.81	2.11	1.94	1.86	2.02
EBIT interest coverage (2)	2.33	2.67	2.47	2.37	2.63
Total debt/capital (1)	62.6%	62.4%	61.4%	61.1%	61.0%
Total adj. debt/capital (2)	59.6%	59.0%	57.5%	57.0%	56.8%
Cash flow/total debt (1)	13.8%	15.1%	13.9%	14.3%	14.6%
Cash flow/capital expenditures	0.60	0.74	1.04	0.93	1.09
EBIT	67.7	67.8	60.9	58.2	59.2
Cash flow from operations	98.1	96.0	79.9	79.0	77.3
Return on partnership equity	8.73%	9.96%	8.42%	7.65%	9.02%
Approved Return on Equity (ROE)	8.93%	9.50%	9.50%	9.60%	9.40%
Deemed common equity in capital structure	35%	35%	35%	34%	34%

(1) Total debt includes operating leases and intercompany debt. Interest expense includes deferred financing fee

(2) Debt excludes $85 million in inter-company loans from AILP. Interest coverage excludes interest expense on inter-company loans.

* In 2004, ALP changed its year-end to December 31. DBRS estimated the results for the 12 months ended December 2004.

The Company

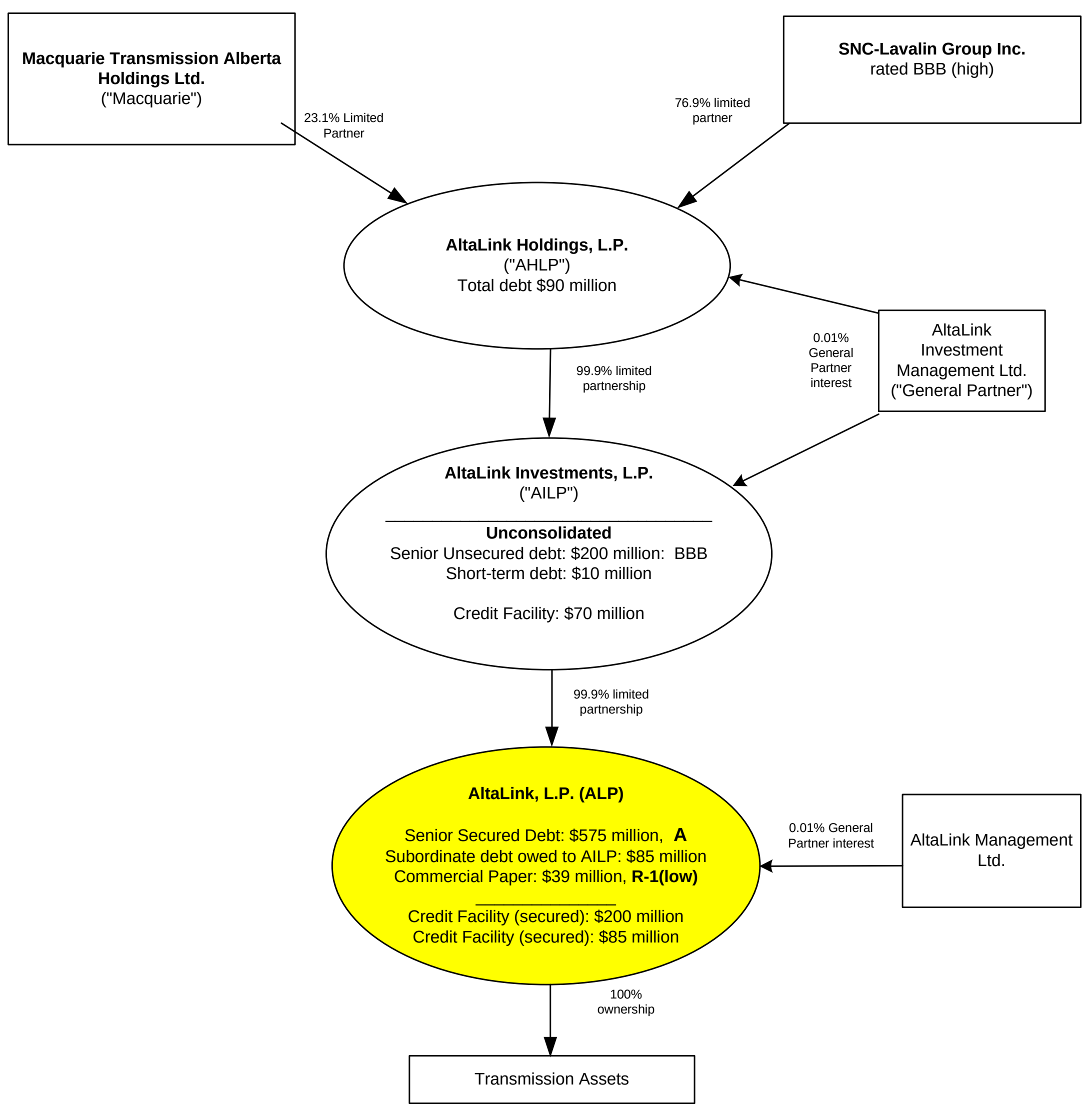
AltaLink, L.P. is a regulated transmission utility in Alberta, serving 85% of the province's population. ALP is wholly-owned by AltaLink Investments, L.P. (AILP) (rated BBB). (See separate DBRS report). AILP is indirectly owned by SNC-Lavalin Group Inc. (76.9%) (rated BBB (high)) and Macquarie Transmission Alberta Holdings Ltd. (23.1%).

Authorized Commercial Paper Limit: $200 million.

RATING UPDATE (Continued from page 1.)

DBRS believes that ALP will continue to finance free cash flow deficits in a conservative manner such that the debt-to-capital ratio remains at approximately the current level of 62.5%. The targeted leverage is more conservative than the regulatory-approved level of 67% for 2007. ALP has two committed indirect owners that have the financial capacity to provide the required equity investments, and ALP should be able to continue to access the long-term debt capital market on attractive terms given its strong financial condition. On the regulatory front, ALP will experience a lower return on equity (ROE) of 8.51% in 2007 (8.93% in 2006) due to lower long-term interest rates. DBRS views the overall regulatory environment as generally supportive, as it allows a full recovery of prudently incurred operating and capital expenses within a reasonable time frame. ALP faces limited credit risk as over 90% of its revenues are derived from the government-backed AESO. The Partnership is experiencing some delays in obtaining regulatory approval for the North-South project, but approvals should be in place in Q4 2007. The Partnership will not commit capital to a project that does not have assured recovery through rates or the AESO.

SIMPLIFIED ORGANIZATIONAL CHART



RATING CONSIDERATIONS

Strengths

(1) ALP owns and operates electric transmission facilities in the province of Alberta. ALP's business risk is relatively low, reflecting its sole business focus on transmission and the fact that ALP (a) has no exposure to volume risk; (b) has limited counterparty risk, as 90% of revenues are derived from the AESO; and (c) can recover all prudently incurred operating costs and approved capital project costs within a reasonable time frame.

(2) ALP provides electric transmission services to 85% of Alberta's population. Alberta has one of the strongest and fastest-growing economies in Canada, which will continue to provide significant growth opportunities for the Partnership.

(3) ALP's financial profile remains solid despite increased free cash flow deficits due to a substantial capital-expenditure program that will continue over the next few years, peaking in 2008 and 2009. For the year ended December 2006, the debt-to-capital ratio was at a reasonable level of 62.6%, which is more conservative than the regulatory-approved level of 67%; EBIT-interest coverage and cash flow-to-debt ratios remained solid at 1.81 times and 13.8%, respectively. The solid financial profile leaves the Partnership well positioned for the significant capital expenditure program projected for the next several years.

(4) The regulatory environment, under the Generic Cost of Capital (GCC) mechanism, remains reasonable reflecting (a) full recovery of prudently incurred operating and capital costs; (b) reduced regulatory lag relating to the cost-recovery process, and (c) transparency associated with equity thickness and ROE methodology.

(5) The following legal and regulatory ring-fencing conditions are considered positive factors in assessing the ALP credit: (a) No cross default between ALP and AILP or between ALP and AHLP; (b) No single consortium member may petition ALP, AILP or AHLP into bankruptcy; and (c) No additional indebtedness shall be issued at ALP if it is reasonable to anticipate that new debt issuance would violate the regulated deemed equity in the capital structure (33% for 2007).

(6) ALP is a highly efficient network operator with high reliability records. The Partnership is independently recognized in the top quartile in reliability, efficiency and network safety.

Challenges

(1) ALP has an aggressive capital expenditure program for the 2007 to 2009 period that includes a number of major transmission projects that were assigned to ALP by the AESO. (See the Regulation Section). These projects, among others, include:

- The Keg Conversion transmission project (estimated cost $66 million, +/-20%). It has been approved and is expected to be completed in Q4 2007.
- The North-South project (estimated cost $495 million +/-20%). The Permit and Licence application has been filed and is pending regulatory approval.
- The South-West project also requires regulatory approval. The cost is estimated at $145 million.

As a result, ALP is expected to incur significant free cash flow deficits during the build-out period, placing pressure on the balance sheet and coverage ratios.

ALP continues to experience delays in obtaining regulatory approval to build the North-South transmission line, and that could potentially expose ALP to rising project costs beyond the amount forecasted in the application. The magnitude and size of the upcoming transmission project exposes the Partnership to construction execution risk, as there is no assurance that cost overruns beyond the regulatory approved amount will be recovered if deemed imprudent by the Alberta Energy and Utilities Board (AEUB). However, DBRS notes that ALP is very experienced in managing these projects and is focused on mitigating the risk of cost overruns.

(2) Significant external financing is required to finance the sizeable free cash flow deficits expected over the 2007-2009 period. ALP is committed to financing the deficits through debt issuances and equity injections from its indirect owners (SNC-Lavalin and Macquarie). Maintaining adequate access to the public debt market is critical to the Partnership during this key build-out phase. DBRS believes the owners have the financing capability and the commitment to fund the equity portion of ALP's projects.

(3) Regulatory-approved ROE levels are low and could continue to decline if long-term interest rates decline. Approved ROE for 2007 declined to 8.51% from 8.93% in 2006.

Regulation

- AltaLink's entire operations are regulated by the AEUB. ALP provides transmission services to the AESO, which provides transmission access to, and receives tariffs from, transmission users.
- Approximately 90% of ALP's revenues are from the AESO, significantly reducing counter-party risk since the AESO is established and supported by the Government of Alberta.
- Under the cost-of-service methodology, ALP is provided a reasonable opportunity to recover its forecast costs, including operating expenses, depreciation, costs of debt and taxes.
- ALP has no exposure to either commodity price risk or volume risk.
- ALP faces the risk of actual expenses exceeding the forecast expenses, but this risk is considered manageable.
- Alberta's regulatory environment has become more predictable since the GCC decision in July 2004. The GCC had the following main features:
  - A common ROE for all utilities in Alberta was established, based on a long-term Government of Canada Bond yield (GCB). The ROE is adjusted annually, based on 75% of the change in the GCB yield, as forecast in the Consensus Forecasts publication issued in November of the previous year.
  - The deemed equity ratio in the capital structure is 35% without a full tax allowance and 33% with tax allowances. ALP's equity ratio was 35% for 2006 and 33% for 2007.
- Overall, DBRS views the GCC decision as generally positive as it reduces uncertainty relating to the ROE-setting methodology and equity thickness.
- In February 2007, ALP received a regulatory decision on its General Tariff Application (GTA) covering the 2007–2008 period. The decision had the following features:
  - ROE for 2007 is 8.51%;
  - The equity ratio is 33%;
  - The final decision on the requested revenue requirements ($213.6 million for 2007 and $325.6 million for 2008) was rendered in February 2007.
- In 2006, ALP was assigned the $495 million 500 kV transmission project by the AESO.
  - This is a two-stage application, consisting of a need application (submitted by the AESO) and a Permit & Licence Application (PLA).
  - In 2006 the AEUB approved the need application. However, a hearing on the PLA presented by ALP is underway with a decision not expected until Q4 2007.
- DBRS believes the Alberta government has a strong commitment to expanding the infrastructure in the province to accommodate customer demand and economic development. Therefore, if the decision is made to proceed with this project and the PLA is approved, the forecast capital costs should reflect the economic reality of the project.

EARNINGS AND OUTLOOK

AltaLink LP	For 12 months ended				
(CAD millions)	Dec. 2006	Dec. 2005	Dec. 2004*	Apr. 2004	Apr. 2003
Total Revenues	199.3	196.1	168.8	154.9	152.2
EBITDA	132.5	132.1	110.7	100.3	109.0
EBIT	67.7	67.8	60.9	58.2	59.2
Gross interest expense	37.0	33.2	32.2	32.3	31.1
Core net income	35.6	37.3	30.9	26.5	30.4
Operating margin	34.0%	34.6%	36.1%	37.6%	38.9%
Return on partnership's equity	8.73%	9.96%	8.42%	7.65%	9.02%
Approved ROE	8.93%	9.50%	9.50%	9.60%	9.40%

* In 2004, ALP changed its year-end to December 31. DBRS estimated the results for the 12 months ended December 2004.

Summary

- EBIT and earnings exhibited an improving trend in 2005 and 2006, reflecting (1) a growing rate base from the increased capital spending that is needed to support the growing demand from a strong economic environment in Alberta, and (2) the relatively predictable nature of the regulated transmission business.
- Key factors affecting earnings are:
  1. Regulatory-approved ROE levels, which have been formula-based since 2004.
  2. 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 construction.
  3. If actual costs exceed forecast costs, earnings will be negatively impacted.
- In recent years, EBIT has been negatively impacted by a lower ROE, which has declined (due to a lower interest environment) to 8.93% in 2006 from 9.5% in 2005. The impact on earnings from a lower ROE has generally been offset by a higher rate base.

Outlook

Earnings are expected to register modest growth in 2007 and should improve considerably in 2008, reflecting the following factors:

- A higher rate base is expected for 2007 and 2008, compared to 2006. In its GTA, ALP requested $213.6 million in revenue requirements for 2007 (an increase of more than 10% over 2006) and $235.6 million for 2008. The decision by the AEUB has been finalized, but ALP is waiting for the decision on its compliance application, which is expected to be rendered in Q2 2007.
  - ALP anticipates the KEG Conversion Project ($66.3 million) will be completed in Q4 2007, increasing the rate base and earnings profile going forward.
- Earnings growth in 2007 is expected to be somewhat offset by a lower ROE 8.51% (8.93% in 2006).
- Over the longer term, earnings growth should remain robust as a sizable backlog of direct assigned capital projects is completed and the invested capital is added to the rate base.

FINANCIAL PROFILE

Cash Flow Statement	For 12 months ended				
(CAD millions)	Dec. 2006	Dec. 2005	Dec. 2004*	Apr. 2004	Apr. 2003
Cash flow from operations	98.1	96.0	79.9	79.0	77.3
Capital expenditures	(199.4)	(139.8)	(89.9)	(92.9)	(71.1)
Contributions from customers	35.3	9.8	13.1	8.4	0.0
Gross Free cash flow	**(66.0)**	**(34.0)**	**3.1**	**(5.5)**	**6.1**
Distributions to AILP	(20.0)	(16.0)	(14.8)	(12.9)	(29.3)
Cash flow before working capital	**(86.0)**	**(50.0)**	**(11.7)**	**(18.3)**	**(23.2)**
Working capital changes	(16.9)	(6.6)	3.4	5.1	(0.9)
Net free cash flow	**(102.9)**	**(56.6)**	**(8.3)**	**(13.2)**	**(24.1)**
Acquisitions	0.0	0.0	0.0	0.0	(0.8)
Divestitures	0.3	0.1	0.9	0.2	0.0
Other	0.0	0.0	0.0	0.0	0.0
Amount to be financed	**(102.6)**	**(56.5)**	**(7.4)**	**(13.1)**	**(24.9)**
Net change in debt	78.5	56.9	7.5	22.6	15.1
Net change in preferreds	0.0	0.0	0.0	0.0	0.0
Net change in equity	25.0	0.0	0.0	0.0	0.0
Net change in other financing	(1.0)	(0.4)	(0.8)	(7.2)	(2.5)
Net change in cash	**0.0**	**0.0**	**(0.7)**	**2.3**	**(12.2)**
Total debt (1)	712.2	637.7	576.1	550.7	528.1
Total debt/capital (1)	62.6%	62.4%	61.4%	61.1%	61.0%
Total adj. debt in capital structure (2)	59.6%	59.0%	57.5%	57.0%	56.8%
Cash flow/ total debt (1)	13.8%	15.1%	13.9%	14.3%	14.6%
Cash flow/capital expenditures (3)	0.60	0.74	1.04	0.93	1.09
EBIT interest coverage (1)	1.81	2.11	1.94	1.86	2.02
EBIT interest coverage (2)	2.33	2.67	2.47	2.37	2.63
Distribution to AILP/Net income	56.6%	43.0%	44.8%	48.8%	96.6%

(1) Total debt include operating leases and $85 million in intercompany loans.

(2) Total adj. debt excludes $85 million in inter-company loans from AILP. Interest coverage excludes interest expense on inter-company loans.

(3) Capital expenditures are net of customer contributions

(*) In 2004, ALP changed its year-end to December 31. DBRS estimated the 12 months ended December 2004.

Summary

ALP's financial profile reflects increasing cash flow from operations and a reasonable strategy to finance the increased free cash flow deficits due to substantial capital expenditures.

- Strong operating cash flows are more than sufficient to finance distributions to AILP and capital spending on system maintenance.
  - Distributions to AILP are designed to meet AILP's debt obligations and other operating expenses. Distributions to ultimate owners during the buildout will be minimal.
- Free cash flow deficits have increased over the past two years, due largely to higher-growth capital expenditures to build new transmission projects, assigned to ALP to meet growing demand.
- The deficits have been financed with a reasonable mix of internal cash flows, customer contributions, new debt at ALP and equity injections from AILP ($25 million in 2006). As a result, the debt-to-capital ratio remains stable at 62.6%, well below the current regulatory approved capital structure at 67%. Management intends to maintain the current leverage level to preserve ALP's interest and cash flow coverages.
- Other key credit metrics, although slightly below 2005 levels as a result of higher debt levels, remain solidly within the current rating category for a low-risk transmission utility with EBIT interest coverage at 1.81 times and the cash flow-to-debt ratio at 13.8%.

Outlook

- Cash flow from operations is expected to grow solidly over the medium term, in-line with the projected growth in the rate base.
- Continued free cash flow deficits are anticipated through 2009, due to higher capital expenditures during this period. DBRS estimates the average capital expenditures will be $350 million per year, of which 70% will be for growth.
- ALP's management is committed to financing the deficits through a combination of debt issuance at ALP and equity injections from the owners, such that ALP's debt-to-capital ratio remains stable at approximately the current level.

- In DBRS's view, this financing strategy is reasonable, reflecting: (1) the low risk of ALP's regulatory-approved capital projects; (2) no capital to be committed unless ALP obtains a regulatory approval for cost recovery; (3) the current strong financial profile at ALP; and (4) a strong commitment from the owners.
- ALP's credit metrics during the build-out period are expected to be under pressure but still consistent with the current ratings. After 2009, barring any new capital projects, capital expenditures are expected to decrease significantly with a significant improvement in all credit metrics.

LONG-TERM DEBT MATURITIES AND BANK LINES

Long-Term Debt Schedule

(CAD millions)	2007	2008	2009	2010	Thereafter	Total
Senior Secured Bonds	0.1	100.0	0.0	0.0	475.9	576.0
Commercial Paper/short-term	0.0	0.0	39.4	0.0	0.0	39.4
Debt owed to AILP	0.0	0.0	0.0	0.0	85.0	85.0
Total (net of current portion)	0.1	100.0	39.4	0.0	560.9	700.4

Credit Facility (As of December 2006)

(CAD millions)	Committed	Drawn	Available	Maturity
Commercial Paper back up facility (secured) (1)	$ 200	0	200	12/13/2009
Credit Facility (secured) (2)	$ 85	0	85	5/4/2009
Total	$ 285	0	285	

(1) The $200 million facility is used to back up CP and for general purposes (established December 2005)

(2) The $85 million (previously $185 million in December 2005) is secured and cannot be used to repay existing debt

Commercial Paper program is $200 million (launched December 2005)

Summary

Long-Term Debt

- ALP finances its operations and capital programs with long-term debt (senior secured, $575.9 million outstanding as of December 2006), and Commercial Paper ($200 million program backed up by a $200 million Credit Facility). The debt-to-capital ratio is managed at approximately 62.5%, which is more conservative than the regulatory-approved level of 67%.
- The debt-repayment schedule is reasonable over the next four years, as ALP only has $100 million of long-term debt due in 2008. Refinancing that debt should be well within ALP's financing capacity given its solid financial profile and adequate access to the public debt markets as demonstrated by the refinancing activity in 2006.
- In 2006, ALP launched a $500 million medium-term notes (MTN) program that is expiring in June 2008. As of March 2007, $350 million is available.
  - Any additional indebtedness is subject to a 75% capitalization ratio test (a contractual covenant).
  - ALP is committed to maintaining its capital structure at or below 62.5%, well below the deemed capital structure as approved by the AEUB (67% for 2007 and 2008).
- ALP has $85 million owed to AILP, maturing in 2012, which includes subordination provisions.
  - Non-payment of either interest or principal on the subordinated debt does not trigger an event of default on senior debt.

Liquidity

- Liquidity requirements will increase over the medium term to accommodate higher capital expenditures and working capital needs. However, DBRS believes ALP has reasonable access to the public debt markets coupled with adequate credit facilities to finance its liquidity needs.
- In late 2005, ALP established a new, secured credit facility of $200 million, which is being used to backstop ALP's $200 million Commercial Paper (CP) program (launched in December 2005).
- This credit facility improves the Partnership's financial flexibility.
- The secured credit line of $185 million was reduced to $85 million at that time. This credit line can be used for capital expenditures and general corporate purposes.
- Liquidity is further supported by the revised AESO customer interconnection agreement in 2006, which gives ALP the right to draw down customer construction contributions to fund customer projects while they are in progress. (The restricted cash account stood at $47.2 million on Dec. 31, 2006).

AltaLink, L.P.

Balance Sheet

(CAD millions)	Dec.31	Dec. 31	Dec. 31		Dec.31	Dec. 31	Dec. 31
Assets	2006	2005	2004	**Liabilities and Equity**	2006	2005	2004
Cash and short-term investments				Short-term debt	39	111	54
Restricted cash	47	30		A/P + accr'ds	68	29	28
Accounts receivable	40	18	16	Regulatory & other liabs.	56	31	4
Inventories	1	1	1	L.t. debt due in one yr.	0	0	0
Prepaid+ regulated	8	2	1	Current Liabilities	163	171	86
Current Assets	96	51	19	Long-term debt	661	511	511
Net fixed assets	1,004	865	903	Asset retirement	56	56	54
Accrued pension and other	22	25	23	Regulatory and other	18	21	132
Goodwill	202	202	202	Shareholders' equity	425	384	363
Total	1,323	1,143	1,146	Total	1,323	1,143	1,146

	12 months or year ended				
Ratio Analysis	Dec.31	Dec. 31	Dec. 31	Apr. 30	Apr. 30
Liquidity Ratios	2006	2005	2004*	2004	2003
Current ratio	0.59	0.30	0.22	0.32	0.04
Total debt/capital (1)	62.6%	62.4%	61.4%	61.1%	61.0%
Total adj. debt/capital (2)	59.6%	59.0%	57.5%	57.0%	56.8%
Cash flow/total debt (1)	13.8%	15.1%	13.9%	14.3%	14.6%
Cash flow/total adj. debt (2)	15.6%	17.4%	16.3%	17.0%	17.4%
Cash flow/capital expenditures (3)	0.60	0.74	1.04	0.93	1.09
Cash flow-distribution/capital expenditures (3)	0.48	0.62	0.85	0.78	0.67
Distribution to AILP/Net income	56.6%	43.0%	44.8%	48.8%	96.6%
Coverage Ratios (times)					
EBITDA interest coverage (times) (1)	3.69	4.10	3.52	3.20	3.72
EBITDA interest coverage (times) (2)	4.55	5.18	4.48	4.08	4.84
EBIT interest coverage (times) (1)	1.81	2.01	1.87	1.79	1.89
EBIT interest coverage (times) (2)	2.33	2.67	2.47	2.37	2.63
EBIT interest coverage (times) (4)	1.89	2.11	1.94	1.86	2.02
Cash flow interest coverage	3.81	4.09	3.61	3.58	3.73
Cash flow/(interest plus distributions to AILP)	2.44	2.71	2.45	2.53	1.86
Total debt/EBITDA	5.37	4.83	5.20	5.49	4.85
Profitability/Operating Efficiency					
EBIT margin	34.0%	34.6%	36.1%	37.6%	38.9%
Net profit margin	17.7%	19.0%	18.1%	17.0%	20.0%
Return on partnership equity	8.7%	10.0%	8.4%	7.7%	9.0%
EBIT/rate base	8.3%	9.1%	8.8%	8.4%	8.8%
Approved ROE	8.93%	9.50%	9.50%	9.60%	9.40%
Equity component in the rate base	35.0%	35.0%	35.0%	34.0%	34.0%
Rate base - mid-year (CAD millions)	820	741	691	691	672
Capital Structure (CAD millions)	**Dec.06**	**Dec. 05**	**Dec. 04**	**Apr. 04**	**Apr. 03**
Short-term debt/CP	39	111	54	33	422
Long-term due in 1 year	0.1	0.1	0.1	0.2	0.0
Long-term debt owed to AILP	85	85	85	85	85
Long-term debt	576	426	426	426	15
Partners' equity	425	384	363	351	337
Total capital	1,125	1,006	928	895	859

(1) Total debt includes $85 million in inter-company loans from AILP and operating leases.

(2) Total adj. debt excludes $85 million in inter-company loans from AILP. Interest coverage excludes interest expense on inter-company loans.

(3) Capital expenditures are net of customer contributions.

(4) Interest expense exclude intercompany interest and deferred financing fee.

* In 2004, ALP changed its year-end to December 31. DBRS estimated the 12 months ended December 2004.

Note:
All figures are in Canadian currency, unless otherwise noted.

DBRS CU Inc.
Jan 2007

Rating Report: January 31, 2007
Press Release: January 31, 2007
Previous Report: November 26, 2004

Insight beyond the rating.

CU Inc.

ANALYSTS

Eric Eng
+1 416 597 7578
eeng@dbrs.com

Michael Caranci
+1 416 597 7304
mcaranci@dbrs.com

Rating Table

Debt Rated	Rating Action	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A (high)	Confirmed	Stable

Rating History

Debt Rated	Current	2006	2005	2004	2003
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & MTNs	A (high)	A (high)	A (high)	A (high)	A (high)

RATING UPDATE

On October 30, 2006, DBRS confirmed the ratings of CU Inc. (CUI or the Company) as follows: Unsecured Debentures & Medium-Term Notes at A (high) and Commercial Paper at R-1 (low), both with Stable trends. The confirmation reflected the continuation of a stable financial profile and the ongoing strength of the Company's regulated operations which underpin the ratings.

The regulatory environment in Alberta, where most of CUI's revenues are generated, continues to remain stable despite the recent Alberta Energy and Utilities Board (AEUB) decisions that established overall lower ROEs for most of CUI's regulated subsidiaries – except Alberta Power (2000) Ltd. (AP (2000)) – which are generation assets subject to legislatively mandated purchase power arrangements (PPAs). While this will have a somewhat negative impact on CUI's expected 2006 earnings and could result in modest pressure on key ratios, DBRS believes the impact is not material enough to impact current ratings. CUI's credit metrics (12 months ended September 2006) remain solid with debt-to-capital at 58.7% and cash flow and interest coverage ratios at 18.0% and 2.42 times, respectively.

CUI's liquidity profile continues to benefit from lower (and less volatile) working capital requirements and the elimination of time lags in commodity cost recovery following the 2004 sale of the zero-margin retail energy business of ATCO Electric and ATCO Gas.

DBRS notes that CUI has incurred free cash flow deficits over the past few years, which created a financing need and put some pressure on the balance sheet. DBRS expects higher future capital expenditures over the medium term, which will likely require financial support from CUI's parent (Canadian Utilities Limited) in the form of equity or reduced dividends in order to maintain current credit metrics. DBRS believes that the parent has the financial flexibility to provide such support given its financial strength and strong cash position. CUI's current financing plan is reasonable as the Company maintains its capital structure in line with levels approved by the AEUB.

Over the longer term, earnings contributed from AP (2000) are expected to decline due to a declining rate base and the termination (in 2013 and 2020) of PPAs, (AP (2000) accounts for an estimated 25% of CUI's earnings). However, this reduction will be partially offset by higher earnings and cash flows from the larger rate bases in the electric and gas distribution and transmission businesses.

DBRS believes that key financial ratios should remain stable assuming: (1) CUI continues to maintain a constructive working relationship with the AEUB; (2) CUI adheres to its current financing strategy; and (3) CUI manages its investment projects to avoid substantial cost overruns.

RATING CONSIDERATIONS

Strengths

- Regulated businesses provide relative stability
- Strong credit metrics/balance sheet
- Diversified energy portfolio
- Strong franchise areas

Challenges

- Free cash flow deficits/high capital expenditure requirements
- Earnings sensitive to weather
- Operational risk related to PPAs
- Low allowed ROEs

THE COMPANY

CUI is a holding company whose operating subsidiaries consist of regulated electric transmission and distribution, gas distribution and transmission utilities serving areas of Alberta, the Yukon and the Northwest Territories (approximately 75% of earnings), and electricity generation assets in Alberta subject to legislatively mandated long-term PPAs (approximately 25% of earnings). CUI is wholly owned by Canadian Utilities Limited (CU) (see separate CU report).

FINANCIAL INFORMATION

Consolidated Basis	12 mos. ended	For the year ended December 31				
($ millions)	Sep. 30, 2006	2005	2004	2003	2002	2001
EBIT	394	408	405	430	412	407
Free cash flow	(155)	(177)	(214)	(46)	(146)	(124)
Total debt in capital structure (1)	58.7%	57.9%	57.5%	56.8%	55.5%	54.9%
Cash flow / total debt (1)	18.0%	18.6%	17.4%	18.6%	19.5%	18.2%
Fixed-charges coverage (times)	2.22	2.39	2.43	2.60	2.45	2.32
EBIT coverage (times)	2.42	2.69	2.78	2.98	2.75	2.47
Dividend payout ratio	76.9%	90.3%	113.3%	55.3%	132.1%	105.6%

(1) Total debt adjusted for preferred shares and operating leases.

Authorized Commercial Paper Limit $400 million (authorized)/$300 million (functional)

RATING CONSIDERATIONS

Strengths

(1) CUI owns regulated electric and gas transmission and distribution assets (along with regulated generation assets protected by legislatively mandated PPAs), and operates in a relatively stable regulatory environment. Although CUI experienced lower allowed ROEs in 2006, DBRS still views the regulatory framework as reasonable, providing reasonable earnings and cash flow stability.

(2) CUI's credit metrics remain reasonable for a utility that benefits from low business risk, and is consistent with current ratings: debt/capital ratio at 58.7%, EBIT coverage at 2.42 times, and cash flow-to-debt at 18.0% (all 12 months to September 2006).

(3) Diversification across different energy sectors (electric transmission and distribution, gas transmission and distribution, and power generation) helps to improve stability of earnings and cash flow and to reduce risks associated with one single business.

(4) CUI serves a relatively large customer base (210,000 electric, 939,600 gas customers) within strong franchise areas. Alberta's economy remains one of the strongest in Canada, although is heavily dependent on the energy sector.

Challenges

(1) Recent higher capital expenditures (which DBRS estimates at approximately 40% for expansion) in regulated electric transmission projects have caused the Company to incur free cash flow deficits, which are expected to continue over the medium term. These deficits will require financial support from the parent in the form of equity or reduced dividends. As

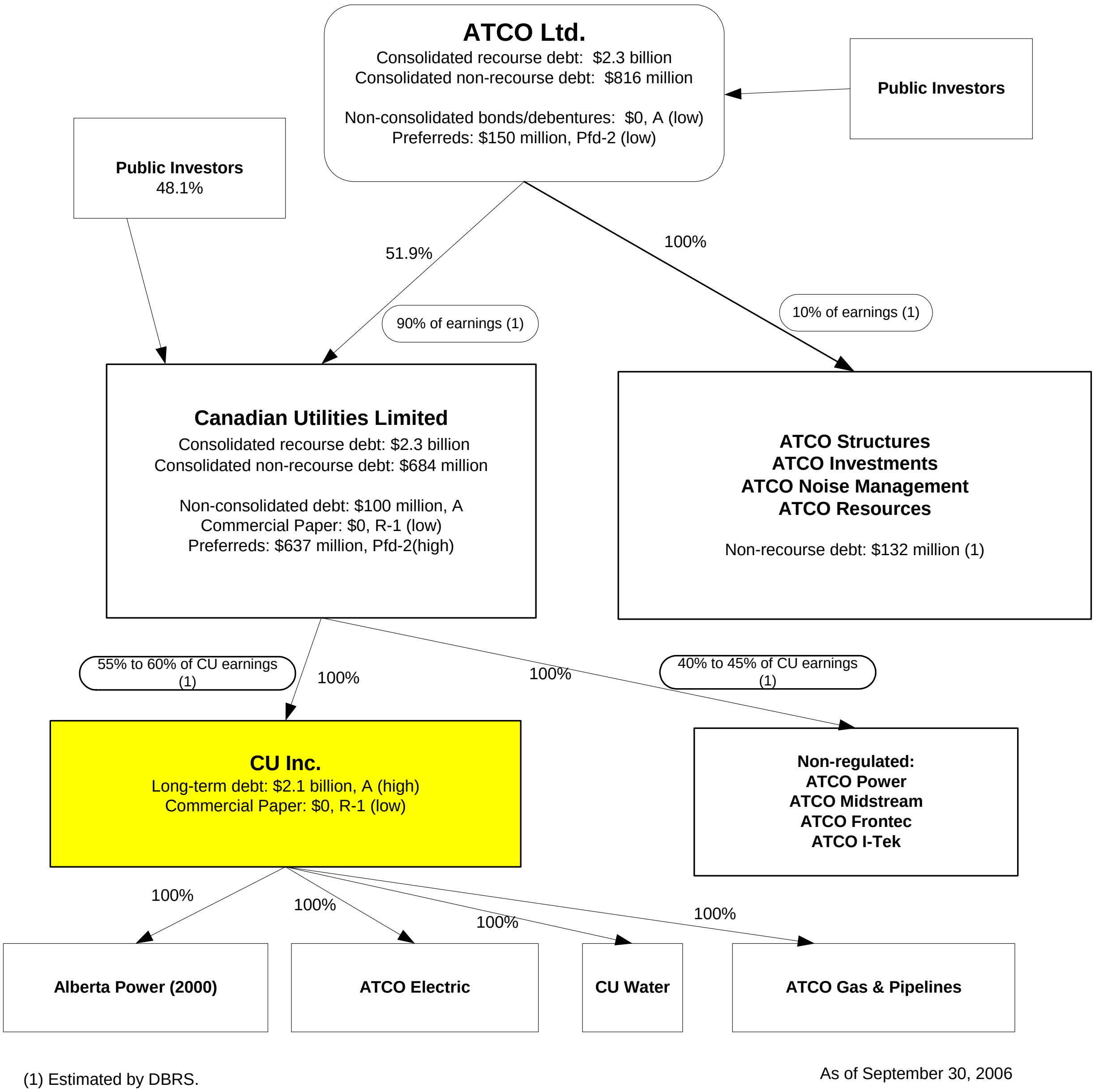
such, a material decline in credit quality of the parent CU (rated "A" by DBRS) could have a credit impact on CUI.

(2) The Company's earnings and cash flows, particularly at ATCO Gas where residential customers account for nearly 50% of volume distributed, are sensitive to the weather. Significant changes in weather from one year to the next can impact earnings and cash flows.

(3) AP (2000) is subject to an incentive/penalty regime relating to generating unit availability. On a net basis, if penalties exceed incentives the shortfall is expensed in the year it occurs. Alternatively, if incentives exceed penalties the excess is amortized to revenues over the remaining life of the PPA. Additionally, AP (2000) faces potential risk associated with higher-than-forecasted capital expenditures to maintain its power plants.

(4) Regulatory-allowed ROE levels are low and could continue to decline if longer-term interest rates decline. ROEs (excluding AP (2000)) are lower than 2005, declining to 8.93% in 2006 from 9.5% in 2005.

SIMPLIFIED ORGANIZATIONAL/DEBT CHART



REGULATION

- CUI's Alberta-based utility operations are regulated by the AEUB. Utility operations in the Yukon and in the Northwest Territories are regulated by regulatory bodies in those jurisdictions (DBRS's primary regulatory focus is on Alberta where most earnings are generated).
- Historically, approved annual revenue requirements for Alberta-based operations were achieved through negotiated settlements or general rate applications, resulting in some degree of uncertainty and time delays.
- The regulatory environment has been more stable since the July 2004 Generic Cost of Capital (GCC) decision, the main features of which include the following:
  - A common ROE for all utilities in Alberta was established based on a long-term Government of Canada bond yield (GCB). The ROE is adjusted annually, based on 75% of the change in the GCB yield, as forecast in the November Consensus Forecast (adjusted for the average difference between the ten-year and 30-year GOC bond yield for October). However, if a utility does not file an application for a particular year, then no adjustment to ROE is made for that year.
  - The return on the debt and preferred equity components of the rate base are based on the actual or forecasted weighted average cost of each utility's debt and preferred shares.
  - The AEUB established an equity level in the capital structure for each utility (currently between 33% and 43%). Changes to the approved capital structures have to be decided by the AEUB.
  - Under the cost-of-service methodology, operating expenses are recovered either through negotiated settlements with counterparties or through general rate applications. Interim rates may be approved, reducing regulatory lags.
- While CUI still faces the risk of not recovering expenses deemed imprudent by the AEUB, DBRS views the GCC decision as reasonable as it reduces some of the uncertainty and regulatory lag in Alberta.

<u>Electricity:</u>

- As a result of the GCC, ATCO Electric's ROE for 2006 was revised downwards to 8.93% from 9.5% in 2005, based on the same common equity levels as previous years (37% for distribution and 33% for transmission). The decline is not expected to have a material impact on earnings.
- AP (2000) holds the generation assets in Alberta that are subject to legislatively mandated PPAs.
  - While AP (2000) is not regulated on an ongoing basis by the AEUB, the PPAs are structured to allow the owners of these assets (generating assets in service as at December 31, 1995) to recover their forecast fixed and variable costs and to earn a rate of return.
  - The PPAs incorporate formula-based ROEs, consisting of a fixed 450 basis point risk premium above forecast ten-year Government of Canada bond yields, adjusted annually.
  - Approved equity in the capital structure under the PPAs has been set at 45%, and allowed ROE was set at 8.75% in 2006 (from 9.49% in 2005), which is still reasonable given the business risk.
  - The PPAs also incorporate a penalty/incentive mechanism that encourages operating efficiencies and places all benefits and risks associated with meeting efficiency targets on the generator.

<u>Gas Transmission & Distribution:</u>

- Effective January 1, 2001, CUI merged and restructured its two gas subsidiaries into ATCO Gas and ATCO Pipelines.
- However, for regulatory purposes separate accounts are maintained for four divisions (ATCO Gas North, ATCO Pipelines North, ATCO Gas South, and ATCO Pipelines South).
- The ROE for 2006 declined to 8.93% from 9.5% in 2005, with a common equity ratio of 38% for both ATCO Gas North and ATCO Gas South.
- The ROE for ATCO Pipelines remains at the 2005 level of 9.6%, with an approved common equity ratio of 43%.
- While the current allowed ROE is low relative to historic levels, the decline is not expected to have a material impact on earnings.

EARNINGS AND OUTLOOK

Consolidated Earnings	For the 12 months ended					
($ millions)	Sept. 2006	Dec. 2005	Dec.2004	Dec. 2003	Dec.2002	Dec.2001
Revenues	1,392	1,490	2,079	2,846	2,236	2,748
EBITDA	655	643	627	637	604	601
EBIT	394	408	405	430	412	407
Gross interest expense	162	151	145	144	150	165
Core net income (after pref'ds)	145	156	167	175	157	149
Net income (reported)	145	156	222	175	225	149
Return on common equity (1)	9.9%	10.8%	11.7%	12.7%	11.8%	11.2%

(1) Net income before non-recurring items.

Segmented Net Earnings						
($ millions)	Sept. 2006	2005	2004	2003	2002	2001
Regulated gas & electric	109	106	114	118	110	100
Power generation	35	50	52	57	48	50
Corporate/eliminations	0	0	1	0	0	0
Non-recurring items	0	0	55	0	67	0
Consolidated net income (after pfd)	145	156	222	175	225	150

Summary

- Earnings as measured by EBIT continued to exhibit a relatively stable trend, which reflects the regulated nature of the business.
  - Key factors affecting earnings are regulatory-approved ROE levels, operating efficiency to outperform the authorized returns and weather.
  - EBIT in 2006 has been affected by lower allowed ROE in the electric, gas and pipeline operations.
  - Warmer weather during the 2005-2006 winter had a negative impact on gas distribution volumes.
  - CUI continues to control operating costs to maintain stable EBIT margins.
  - EBIT is also helped by the early 2006 finalization of ATCO Electric’s and ATCO Gas’s 2005 and 2006 rates by the AEUB.
- The 2004 sale of ATCO Electric’s and ATCO Gas’s retail energy business to Direct Energy Marketing Limited (DEML) had no impact on earnings (with the exception of a one-time gain on the sale) since it was a zero-margin business, but does account for the significant drop in revenues.
- Approximately 75% of current earnings are contributed by electric distribution and transmission, and gas distribution and transmission, with the balance sourced from regulated generation.
  - Earnings from electric distribution are more stable than those of gas distribution, which is weather sensitive.
  - Earnings from gas transmission operations are under relatively higher competitive pressure than the distribution businesses.
  - Earnings from regulated generation are expected to decline gradually due to a declining rate base. Earnings recently declined due to the expiry of an 88 MW PPA.

Outlook

- EBIT is expected to register modest growth over the medium term, with the primary drivers being economic expansion in the franchise area and growth in the rate base due to large capital projects (electricity transmission, natural gas distribution, the ongoing relocation of natural gas meters and replacement of aging facilities).
  - Earnings contributions to CUI from the distribution and pipeline transmission businesses should increase due to additional capital investments.
  - A declining rate base in regulated generation is expected to gradually lower earnings at AP (2000). However, earnings at this segment should remain reasonable until several PPAs expire in 2013.

FINANCIAL PROFILE

Consolidated Cash Flow Statement	For the 12 months ended					
($ millions)	Sept. 2006	Dec. 2005	Dec.2004	Dec. 2003	Dec.2002	Dec.2001
Cash flow from operations	426	418	383	389	368	332
Dividends	112	141	189	97	208	157
Capital expenditures	537	498	458	383	347	334
Contributions from customers	68	44	51	46	41	35
Gross Free Cash Flow	(155)	(177)	(214)	(46)	(146)	(124)
Working capital changes	(1)	89	120	(62)	(142)	260
Free Cash Flow	(155)	(88)	(94)	(107)	(289)	136
Acquisitions	0	0	0	0	0	0
Divestitures/Asset dispositions	(12)	37	18	12	108	65
Other/Adjustment	(15)	(25)	0	(4)	23	38
Amount to be Financed	(183)	(76)	(76)	(99)	(158)	239
Net change in debt	185	60	380	(61)	(3)	(136)
Net change in preferreds	0	0	0	0	0	0
Net change in equity	0	0	0	0	0	0
Net change in other	(3)	(3)	(7)	(51)	46	27
Net change in cash	(1)	(19)	297	(211)	(115)	131
Total debt in capital structure	58.7%	57.9%	57.5%	56.8%	55.5%	54.9%
EBIT interest coverage	2.42	2.69	2.78	2.98	2.75	2.47
Total debt/EBITDA (1)	3.62	3.50	3.50	3.29	3.13	3.04
Cash flow/adjusted total debt (1)	18.0%	18.6%	17.4%	18.6%	19.5%	18.2%
Common dividend payout (2)	76.9%	90.3%	113.3%	55.3%	132.1%	105.6%

(1) Total debt adjusted for debt equivalent and operating leases.
(2) Dividends divided by net income after preferred dividends.

Summary

The Company's financial profile remains relatively stable, despite significant free cash flow deficits during the past two years, reflecting the following:

- Relatively strong cash flow from operations with moderate growth.
- Increased capital investments in regulated electric transmission and natural gas projects.
- Decreased working capital fluctuations with the 2004 retail business sale.
- Benefit of cash contributions from utility customers for certain new projects undertaken by the Company.
- Dividends managed in order to maintain a stable capital structure.

As a result, key credit metrics remained relatively stable: debt-to-capital at 58.7%, EBIT interest coverage of 2.42 (times) and cash flow-to-debt of 18.0%, which remain reasonable for the current rating category.

Outlook

- Although cash flow from operations is expected to continue to grow over the next few years in line with the growth in rate base, continued cash flow deficits are expected due to higher capital expenditures.
  - Annual capital expenditures are estimated by DBRS to average approximately $550 million from 2006 to 2009 due to a number of larger capital projects.
  - Higher capital expenditures are also expected from the implementation of mercury emission standards for coal-fired generating plants through a new Alberta regulation that came into force in March 2006. Owners are expected to submit proposals on capturing at least 70% of the mercury in coal burned in their plants by March 2007. It is expected that the PPAs associated with the Company's coal-fired plants will allow them to recover most of the costs related to compliance.
  - DBRS estimates over 40% of total expected capital spending will be for expansion primarily in the electric and

gas distribution businesses, which will increase the rate base and future earnings and cash flows.
- To finance these deficits, CUI's financing strategy includes issuing debt at CUI and managing dividend payments to CUI's parent (Canadian Utilities Limited, CU) in a way that would maintain the capital structure at CUI in line with current ratings. DBRS believes that CU has the financing capability and financial flexibility to adhere to this strategy.
- Key credit ratios are expected to remain stable, assuming the financing strategy is successfully implemented.

LONG-TERM DEBT MATURITIES AND BANK LINES

Debt Maturity Schedule (as at December 31, 2005)

$ millions	CU Inc.	% of Total Outstanding
2006	175	8%
2007	55	3%
2008	100	5%
2009	125	6%
Thereafter	1,668	79%
Total	2,123	100%

Summary

- CUI's liquidity position remains strong, reflecting healthy operating cash flow, reduced working capital requirements, and moderate short-term debt repayments along with sufficient credit facilities.
- CUI has a $400 million commercial paper (CP) program backed by a $300 million revolving credit facility.
  - CUI is committed to issuing only up to the back-up amount of $300 million, a key factor for the R-1 (low) rating.
  - Liquidity is further supported by the fact that CUI has negligible credit guarantees.
- The debt repayment schedule over the next few years is viewed by DBRS as moderate and well within the re-financing capacity of CUI.
- DBRS believes that CUI's operating cash flows and credit facilities are sufficient to support its working capital requirements and capital spending needs.
- CUI has an MTN Debenture program which supports financial flexibility.
- CUI's regulated subsidiaries have $265.5 million in preferred equity all held directly by CU, which are included in the regulatory-approved capital structure.

DESCRIPTION OF OPERATIONS

<u>(1) Electric Transmission and Distribution</u>

- This segment serves approximately 210,900 electric customers in Alberta, the Yukon and the Northwest Territories.
- As a result of ATCO Electric's and ATCO Gas's sale of their retail business, neither is responsible for customers' commodity procurement. Working capital and liquidity requirements were also reduced with the sale.
- The business is low risk, with virtually no competition within the franchise areas. Returns on investments are regulated, and as such, regulatory risk is the most significant business risk.
- The regulatory environment is viewed by DBRS as stable, with a reasonable regulatory lag for recovery of operating costs.
- Allowed ROE for ATCO Electric in 2006 is lower than historically granted, but still remains acceptable at 8.93% on a 37% common equity component for distribution and 33% for transmission.
- Due to increased capital expenditure requirements to meet customer demand and maintain system reliability, the segment is expected to generate free cash flow deficits over the medium term.
- DBRS believes that the segment's financial metrics should remain stable as the Company intends to finance its deficits in a way that will keep the actual debt/capital ratio close to the regulatory-allowed ratio.
- Electric transmission and distribution is the largest earnings contributor to CUI.

(2) Gas Transmission & Distribution

- ATCO Gas and ATCO Pipelines operate gas distribution and transmission businesses serving approximately 939,600 customers.
- Business risk is reasonably low, reflecting a stable regulatory environment, reasonable regulated returns and no gas price risk.
- The gas distribution business is very sensitive to weather, which can significantly influence the segment's cash flow stability.
- Most of the transmission pipelines are strategically located, with increasing demand to connect producers with major pipelines.
- Financial risk is moderate reflecting the external financing that will be required to finance ongoing capital expenditures. DBRS believes that the Company's financing strategy is reasonable and achievable and will result in continued strong credit metrics.
- Allowed ROE for ATCO Gas in 2006 declined to 8.93% from 9.50% in 2005, with an equity ratio of 38%. The lower allowed ROE will have a modest impact on earnings, but not significant enough to materially impact credit metrics.
- Allowed ROE for ATCO Pipelines is 9.6% with an equity ratio of 43%.

(3) Regulated Generation: Alberta Power (2000)

AP (2000) Assets

Name	Type	Nameplate Capacity (MW)	PPA Counterparty	Expiry Date
Battle River (1)				
Unit 3	coal-fired steam turbine	150	Enmax Corp.	2013
Unit 4	coal-fired steam turbine	150	Enmax Corp.	2013
Unit 5	coal-fired steam turbine	370	Enmax Corp.	2020
		670		
Sheerness (2) (3)				
Unit 1	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
Unit 2	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
		380		
Rainbow	natural gas turbine	88	Merchant (4)	
Sturgeon	natural gas turbine	18	Merchant	
		1,156		

(1) ENMAX became PPA purchaser in May 2006.
(2) AP (2000)'s ownership of 760 MW of gross capacity.
(3) TransCanada Energy Ltd. became the PPA purchaser in Jan. 2006.
(4) PPA expired December 31, 2005.

- AP (2000) holds generation assets in Alberta that are subject to legislatively mandated PPAs.
- While AP (2000) is not regulated on an ongoing basis by the AEUB, the PPAs are structured to allow the owners of these assets (generating assets in service as at December 31, 1995) to recover their forecast fixed and variable costs and to earn a rate of return.
- 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, adjusted annually.
- In the event of a PPA counterparty default CUI could terminate the PPA, a process in which the PPA would be deemed to have been sold from the power-buying counterparty to the Balancing Pool. This provides CUI with a strong back-stop credit on these PPAs (the Balancing Pool carries an Issuer Rating of AA, see separate DBRS report).
- AP (2000) faces decreasing earnings as the rate base declines over time.
- Coal costs are fixed through long-term contracts, with such costs reflected in the PPAs.

  - The equity component for the generation assets under the PPAs has been set at 45%, which is reasonable given the business risk. The ROE for 2006 was set at 8.75%, down from 9.49% in 2005.
  - The PPAs incorporate incentives that encourage operating efficiencies and allocate all benefits and risks associated with meeting availability targets to the generator.
- The business risks for AP (2000) established under the PPAs include the following:
  - AP (2000) is subject to an incentive/penalty regime relating to generating unit availability. On a net basis, if penalties exceed incentives the shortfall is expensed in the year it occurs. Alternatively, if incentives exceed penalties the excess is amortized to revenues over the remaining life of the PPA.
  - AP (2000) faces potential risk associated with higher-than-forecasted capital expenditures to maintain its power plants.
- Facilities with expired PPAs become merchant generation and are exposed to commodity-price risk and decommissioning risk (if decommissioned at expiry of the PPA, decommissioning costs are included in PPAs).
- 88 MW of Rainbow generation became merchant in 2006, with another 300 MW of PPAs at Battle River to expire in 2013.

Note:
All figures are in Canadian dollars unless otherwise noted.

CU Inc.

Balance Sheet ($ millions)

Assets	Sept. 2006	Dec. 2005	Dec. 2004
Cash + equivalents	11	35	64
Accounts receivable	160	198	243
Inventories	70	66	158
Prepaids + other	26	26	13
Current Assets	266	326	477
Net fixed assets	4,017	3,878	3,645
Deferred assets	46	49	43
Other assets	28	38	36
Total	4,357	4,291	4,202

Liabilities & Equity	Sept. 2006	Dec. 2005	Dec. 2004
Short-term debt	136	27	33
A/P + accr'ds.	123	174	163
Other	2	23	38
L.t. debt due one year	175	175	125
Current Liabilities	436	399	360
Deferred credits	232	229	204
Long-term debt	1,948	1,948	1,938
Perpetual pfd. equity	257	257	257
Shareholders' equity	1,485	1,459	1,444
Total	4,357	4,291	4,202

For the 12 months ended

Ratio Analysis

	For the 12 months ended					
Liquidity Ratios	Sept. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002	Dec. 2001
Current ratio	0.61	0.82	1.33	0.91	1.08	1.14
Cash flow/total adjusted debt (1)	18.0%	18.6%	17.4%	18.6%	19.5%	18.2%
Cash flow/capital expenditures (1)	0.92	0.93	0.95	1.13	1.18	1.10
Cash flow-dividends/capital expenditures (1)	0.71	0.65	0.53	0.88	0.58	0.63
% Total debt in capital structure (1)	58.7%	57.9%	57.5%	56.8%	55.5%	54.9%
Common equity in capital structure (1)	36.8%	37.5%	37.8%	38.3%	39.3%	39.7%
Common dividend payout	76.9%	90.3%	113.3%	55.3%	132.1%	105.6%
Coverage Ratios						
EBITDA interest coverage	4.01	4.24	4.30	4.40	4.03	3.65
EBIT interest coverage	2.42	2.69	2.78	2.98	2.75	2.47
Fixed-charges coverage	2.22	2.39	2.43	2.60	2.45	2.32
Total adjusted debt/EBITDA (1)	3.62	3.50	3.50	3.29	3.13	3.04
Returns on equity						
Actual return on avg. equity (before extras.)	9.87%	10.75%	11.66%	12.72%	11.83%	11.22%
Approved ROE - ATCO Electric (T&D)	8.93%	9.50%	9.60%	9.40%	NA	NA
Approved ROE - ATCO Gas	8.93%	9.50%	9.50%	9.50%	9.75%	9.75%
Approved ROE - ATCO Pipelines	9.60%	9.60%	9.60%	9.50%	9.75%	9.75%
Approved ROE - PPAs	8.75%	9.99%	9.99%	9.99%	10.18%	10.29%

(1) Adjusted for preferred and operating lease.

(2) Prior to 2004 is not comparable due to non-margin revenues from the retail business.

OPERATING STATISTICS

ATCO Electric

Electricity distribution (millions of KWh)	2005%	2005	2004	2003	2002
Industrial	66%	6,583	6,597	6,502	7,143
Commercial	18%	1,826	1,796	1,729	1,655
Residential	10%	1,023	1,032	982	963
Rural, REAs and other	5%	494	485	555	463
Total	100%	9,926	9,910	9,768	10,224

Customers	2005%	2005	2004	2003	2002
Industrial	5%	10,847	10,691	10,484	10,623
Commercial	14%	28,673	28,068	27,386	27,448
Residential	67%	141,806	138,066	135,263	131,143
Rural, REAs and other	14%	29,536	29,421	29,135	28,632
	100%	210,862	206,246	202,268	197,846

ATCO Gas

Gas Distribution (petajoules)	2005%	2005	2004	2003	2002
Residential	48%	103.800	107.300	109.300	110.100
Commercial	45%	96.900	98.100	100.100	102.200
Industrial	7%	14.400	14.500	14.600	15.000
Other	0%	0.400	2.800	6.000	4.600
Total	100%	215.500	222.700	230.000	231.900

Customers	2005%	2005	2004	2003	2002
Residential	91%	858,618	834,883	809,921	785,410
Commercial	9%	80,630	79,084	77,436	76,153
Indutrial	0%	350	359	367	359
Other	0%		21	43	30
Total	100%	939,598	914,347	887,767	861,952

ATCO Pipelines (terajoules/day)	2005%	2005	2004	2003	2002
Contract demand					
Producer	27%	1,291	1,253	1,314	1,463
Industrial	21%	1,015	1,054	1,075	1,131
Distribution	2%	93	89	39	39
Affiliates	50%	2,431	2,210	2,171	2,257
Total	100%	4,830	4,606	4,599	4,890
IT/OR/Variable Volumes					
Producer	50%	243	257	209	156
Industrial	50%	241	258	231	135
Distribution	0%	2	7	18	18
Total	100%	486	522	458	309

DBRS FortisAlberta
May 2007

Rating Report

Report Date: May 25, 2007
Press Release: May 25 2007
Previous Report: November 25, 2005

Robert Filippazzo/Jade Freadrich
+1 416 597 7340/+1 416 597 7351
rfilippazzo@dbrs.com/jfreadrich@dbrs.com

FortisAlberta Inc.

RATING

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

RATING HISTORY	Current	2006	2005	2004	2003	2002
Senior Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A

RATING UPDATE

DBRS has confirmed the ratings of the Senior Unsecured Debt of FortisAlberta Inc. (FortisAlberta or the Company) at A (low) with a Stable trend, based on the fully regulated operations of the Company, the favourable operating area and its relatively stable credit metrics.

The Alberta regulatory environment has historically been a challenge for the Company, but it continues to show signs of improvement. The historical impact of regulatory lag has been reduced now that the Company is filing rate applications for two years at a time (instead of annually), as well as the establishment of the Generic Cost of Capital in July, 2004.

FortisAlberta intends to maintain its capital structure at a level of 60% debt and 40% equity, which is slightly more conservative than the Alberta Energy Utility Board (AEUB) approved capital structure of 63% debt and 37% equity. Through the Generic Cost of Capital formula, the Company's approved return on equity (ROE) decreased to 8.51% for 2007 from 8.53% in 2006, as it is tied to the long-dated Government of Canada bond.

Increased capital expenditures, primarily driven by customer growth, as well as system upgrades, are expected to exceed $650 million over the next three years.

DBRS continues to believe that the Company's largest challenge over the medium term will be the free cash flow deficits caused by the significant ongoing capital expenditures. While the Company will partially finance these deficits by drawing on its bank facility, as well as through future debt issuances and internally generated cash, DBRS expects that as the Company generates free cash flow deficits, its parent, Fortis Inc. (Fortis), will be required to provide equity injections in order to maintain the Company's capital structure. (Continued on page 2.)

RATING CONSIDERATIONS

Strengths

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

Challenges

- Major capital expenditure program underway
- Low regulated rates of return
- Cumbersome regulatory environment

FINANCIAL INFORMATION

	As at	For the year ended December 31				
($ millions)	Mar. 31, 2007	2006	2005	2004	2003	2002
EBIT	65.8	66.8	64.3	64.7	69.1	75.5
EBIT / Interest coverage	2.00	2.15	2.55	2.32	2.31	2.95
% adjusted debt in capital structure (1)	60.8%	62.5%	60.1%	59.4%	59.0%	58.3%
Cash flow / Total adjusted debt (1)	14.2%	13.4%	19.2%	20.0%	8.1%	14.3%
Cash flow / Capital expenditures (times)	0.40	0.38	0.70	0.82	0.33	0.62
Free cash flow	(161.7)	(178.5)	(71.8)	(8.6)	(15.7)	210.4
Approved ROE	8.51%	8.93%	9.60%	9.50%	9.50%	9.50%
Return on average common equity	11.1%	11.8%	5.6%	8.1%	8.8%	6.9%

(1) Adjusted for operating leases

THE COMPANY

FortisAlberta is a regulated electricity distribution company with approximately 433,000 customers that accounts for approximately 56% of the Alberta distribution grid. It has been operating since September 2000 and is a wholly owned indirect subsidiary of Fortis Inc., a Canadian public holding company focused primarily on electric utility operations in Canada, the Caribbean and the United States. FortisAlberta'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.

RATING UPDATE (Continued from page 1.)

Partially offsetting this are the higher depreciation rates approved in the latest negotiated settlement. Ultimately, DBRS believes the key credit ratios will weaken modestly during the build-out period, but they will remain within ranges consistent with the assigned rating.

DBRS believes that FortisAlberta's operations will be relatively stable going forward, given the regulated environment it operates in and the strong growth in the size of the Company's rate base. DBRS notes that on May 17, 2007, Fortis completed the acquisition of all the outstanding shares of Terasen from a wholly owned subsidiary of Kinder Morgan Inc. (KMI) for $3.7 billion, including assumed debt of approximately $2.3 billion. The transaction includes only Terasen's natural gas distribution businesses: Terasen Gas Inc. (rated "A" and R-1 (low) – see DBRS report March 16, 2007), Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. The transaction does not include the refined products and crude oil pipelines assets that were formerly owned by Terasen. DBRS confirmed both Fortis and FortisAlberta's ratings shortly after the acquisition announcement.

RATING CONSIDERATIONS

Strengths

(1) FortisAlberta operates exclusively as a regulated electricity distributor, a stable and relatively low-risk business. Approximately 85% of distribution revenue was derived from fixed or largely fixed billing determinants during 2006. The regulatory framework for the distribution business is currently based on a cost-of-service methodology that 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 and 37% equity, although the Company has indicated that it intends to maintain a more conservative 60% debt and 40% equity capital structure for the overall entity.

(2) 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 growth and, consequently, its earnings and cash flow.

(3) 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 the summer months do not tend to require air conditioning to the same extent as in other regions. As a result, there is minimal risk that the demand forecast will significantly differ from actual demand, increasing the stability of the Company's earnings and cash flow.

Challenges

(1) The Company is currently in the midst of a major capital expenditure program that is necessary to meet the rapid growth in population and power demand in its service territory. Approximately $650 million in spending is planned over the next three years in order to meet this growth, which is expected to cause continued free cash flow deficits and some weakening of key credit ratios. There is a lag in the recovery of capital costs as the rate base is measured at mid-year; costs incurred after this date are not collected until they are included in the following year's rate base. Cash flow deficits are expected to be funded with a combination of debt and equity contributions from Fortis in order to maintain the current capital structure.

(2) FortisAlberta's financial profile is negatively impacted by recently growing free cash flow deficits and a low allowed ROE, but it continues to remain acceptable for the ratings. The rates of return and equity capitalization for rate-making purposes allowed by the AEUB have been low in recent years. As a result of the low interest-rate environment, the approved ROE for 2007 declined to 8.51%, compared with 8.93% in 2006, as calculated by the automatic adjustment formula.

(3) Historically, Alberta-based utilities have been burdened by material time lags associated with the regulatory process. Regulatory decisions are often delivered well after the fiscal period in question, resulting in charges against the current year's earnings to reflect prior-period adjustments. Despite operating under a cost-of-service regulatory framework, the Company is not able to recover costs in excess of those forecast when rates are set. Recently, however, the regulatory environment has shown signs of improvement. Regulatory lag has also been reduced because the Company is filing rate applications for two years at a time (instead of annually), as well the establishment of the Generic Cost of Capital formula in July, 2004.

REGULATION

- FortisAlberta is regulated by the AEUB, based on a cost-of-service methodology. The Company has the opportunity to recover all prudently incurred operating expenses, depreciation, income tax, interest on debt that supports regulatory assets, as well as earning a reasonable ROE. The cost of power is passed through to customers.
- As of January 1, 2001, all customers acquired the right to choose their electricity retailers with the distribution utility continuing to provide distribution services. While electricity distribution networks continue to be regulated, independent retailers became eligible to sell electricity to end-use customers on a competitive basis. All distribution services must still be arranged exclusively with the owner of an electricity distribution network in that owner's service area.
- A negotiated settlement was approved by the AEUB in June 2006 for 2006 and 2007 rates. The agreement set the distribution revenue requirements at $217 million and $228 million in 2006 and 2007 respectively, which translates to an approximate 1% reduction in base distribution rates over two years.
- In July 2004, the AEUB issued a Generic Cost of Capital decision that established a common approach for setting the ROE – based on the forecast long-term Canada bond yields – for all electricity and natural gas utilities under its jurisdiction.
  - Approved ROE for 2007 declined to 8.51%, compared with 8.93% in 2006, as calculated by the automatic adjustment formula.
- The Company filed a comprehensive depreciation study in December 2004 that resulted in approved depreciation rates increasing from an average of 4.08% in 2005 to 4.14% in 2006.
- The Company's deemed capital structure – per the guidelines of the Generic Cost of Capital formula for a fully taxable electric distribution company – is 63% debt to 37% equity.
- FortisAlberta intends to file a rate application for 2008 and 2009 in the second quarter of 2007.
- Under pending legislation, the Province of Alberta intends to restructure the AEUB in an attempt to reduce regulatory lag. If the legislation passes, a newly formed Alberta Utilities Commission would supervise power deregulation, consumer price protection and the electricity transmission and distribution grid effective January 2008.

EARNINGS AND OUTLOOK

	As at	For the year ended December 31				
($ millions)	Mar. 31, 2007	2006	2005	2004	2003	2002
Revenues	238.6	235.6	226.3	212.9	202.1	248.1
EBITDA	136.9	135.5	125.7	117.4	113.7	158.1
EBIT	65.8	66.8	64.3	64.7	69.1	75.5
Gross interest expense	32.0	30.1	24.2	26.4	29.2	24.9
Core net income	43.8	41.4	17.5	24.5	26.6	21.3
Net income (reported)	43.8	41.4	31.1	24.5	(53.4)	27.5
Return on average common equity	11.1%	11.8%	5.6%	8.1%	8.8%	6.9%

Summary

- Energy deliveries and the total number of customers has increased since 2005, but the impact was offset by a 1.9% rate decrease, effective January 1, 2006. The Company's reported 2005 net income was positively impacted by the resolution of tax matters and the finalization of load settlement amounts relating to a prior period.
- EBIT has been steady over the last several years, however, net earnings for the twelve months ended December 31, 2006 and for the 12 months ending March 31, 2007 increased primarily due to a decrease in income tax costs, partially offset by decreased revenues combined with increased operating, depreciation and interest expense.
- Interest expense has increased from 2005 as a result of debt financing for the Company's large capital expenditure program.
- Current rates include only income taxes that are currently payable as prescribed by the 2006/2007 negotiated settlement approved in June 2006. Future taxes caused by temporary differences will be collected in the years in

which they become payable. As such, the Company recognizes future income taxes for certain deferral amounts where the future income taxes will not be collected in future customer rates. FortisAlberta is only now recognizing future income taxes for certain deferral amounts that will not be collected in future customer rates.

- EBIT and net income are expected to increase over the medium term due to an expansion of the Company's rate base that anticipates customer and load growth.

Outlook

- A decline in the allowable ROE to 8.51% in 2007 from 8.93% in 2006 will partially offset the positive impact of the larger rate base.

FINANCIAL PROFILE

($ millions)

	As at	For the year ended December 31				
Cash Flow Statement	Mar. 31, 2007	2006	2005	2004	2003	2002
Core net income	43.8	41.4	17.5	24.5	26.6	21.3
Depreciation and amortization	71.5	69.1	61.8	55.9	46.3	82.6
Other and future income taxes	(25.1)	(25.5)	14.4	8.4	(37.7)	(43.3)
Cash Flow From Operations	**90.2**	**85.0**	**93.6**	**88.9**	**35.2**	**60.6**
Common dividends	(14.0)	(14.0)	(12.0)	(6.0)	-	(0.3)
Capital expenditures	(224.6)	(222.6)	(133.6)	(108.1)	(105.5)	(97.4)
Free Cash Flow Before W/C Changes	**(148.4)**	**(151.6)**	**(51.9)**	**(25.2)**	**(70.2)**	**(37.1)**
Net changes in working capital	(13.3)	(26.9)	(19.9)	16.6	54.5	94.4
Net Free Cash Flow	**(161.7)**	**(178.5)**	**(71.8)**	**(8.6)**	**(15.7)**	**57.4**
Other investing activities	2.8	2.2	0.9	0.7	1.9	4.1
Other adjustments	–	-	13.6	-	2.0	-
Amount to be financed	**158.9**	**(176.4)**	**(57.3)**	**(8.0)**	**(11.9)**	**61.4**
Net debt financing	112.7	145.9	56.7	(15.1)	11.5	(176.2)
Net equity financing	50.0	30.0	-	(15.0)	50.0	(36.0)
Other financing	(2.1)	(1.3)	(0.4)	(5.8)	(3.1)	(2.3)
Net change in cash	**1.7**	**(1.8)**	**(1.0)**	**(43.8)**	**46.6**	**(153.1)**
EBIT / Interest coverage (times)	2.00	2.15	2.55	2.32	2.31	2.95
Total adjusted debt / EBITDA (1)	4.65	4.68	3.88	3.79	3.80	2.69
Cash flow / Total adjusted debt (1)	14.2%	13.4%	19.2%	20.0%	14.3%	14.3%
% adjusted debt in capital structure (1)	60.8%	62.5%	60.1%	59.4%	58.3%	58.3%
Dividend payout ratio	15.5%	16.5%	12.8%	6.7%	0.0%	0.4%

(1) Adjusted for operating leases

Summary

- Operating cash flow for the 12 months ended March 2007 and December 31, 2006 have benefited from an income tax recovery and increased depreciation, offset primarily by an increase in deferred regulatory assets.
- The large ongoing capital expenditure program has caused a continuation of free cash flow deficits. Higher capital expenditures mainly result from improvements to the distribution network and the expansion and upgrades to the power system, which are necessary to meet customer growth of the strong provincial economy.
- FortisAlberta has financed the cash flow deficits with a combination of incremental debt financing as well as equity injections from Fortis, maintaining a reasonably stable debt/capital ratio.
- While the debt to capital ratio has remained stable since 2002, key coverage metrics have declined modestly due to lower allowed ROE and increased debt levels.

Outlook

- The Company is expected to report free cash flow deficits over the medium term as a result of a three-year $650 million capital expenditure program that DBRS estimates will result in a cumulative cash flow deficit of between $325 million and $375 million.
- In order for the Company to maintain its AEUB-approved credit profile and capital structure during this capital expenditure program, DBRS expects FortisAlberta to fund itself through external debt financing and equity injections from Fortis.
- Credit coverage metrics are expected to weaken modestly during the build-out period, but DBRS expects the Company to benefit

over the medium term as the company recovers construction costs through an increased rate base.

- DBRS believes that despite the free cash flow deficits and modestly weakened credit coverage metrics the Company's financial profile should continue to remain acceptable for the current ratings.

LONG-TERM DEBT MATURITIES AND BANK LINES

Senior unsecured debentures	Amount (millions)	Maturity	Coupon	Terms
Series 04-1	200.0	2014	5.33%	semi-annual
Series 04-2	200.0	2034	6.22%	semi-annual
Series 06-1	100.0	2036	5.40%	semi-annual
Series 07-1	109.9	2047	4.99%	semi-annual
	609.9			

Summary

- The company has no debt maturities over the near term.
- In March 2006, the syndicated credit facility was increased to $200 million from $150 million, maturing May 2010. With the consent of the lenders, the company has the ability to increase this facility by $50 million.
  - As of March 31, 2007, usage was limited to $44.8 million of letters of credit.
- The Company has available up to $20 million of unsecured demand credit facilities. There was no drawdown as of March 31, 2007.
- In December 2006, the Company filed a $350 million shelf prospectus, which will be used to help fund the current capital expenditure program. $110 million was issued under this shelf in January 2007, in order to repay existing short term debt, incurred primarily to fund capital expenditures.

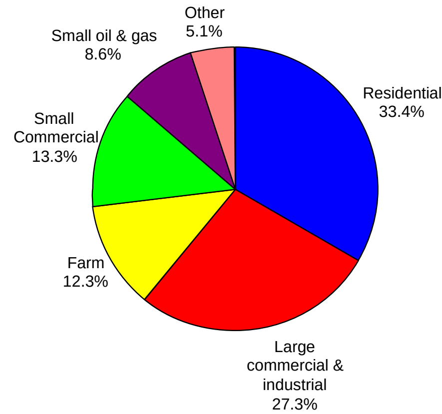
Outlook

- The $200 million credit facility should provide sufficient liquidity to meet any short-term funding requirements. If necessary, the Company has the ability to increase its borrowing limit to $250 million.
- While maintaining a long term capital structure of 40% equity and 60% debt, the Company will issue additional debt in the near term to finance its large capital expenditure program.

Description of Operations

- FortisAlberta is a regulated, electricity distribution company that has been operating since September 2000. The Company is not involved in the generation, transmission or the direct sale of electricity to end-use customers.
- 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 with its approximately 943 employees, distributes electricity to approximately 433,000 customers and approximately 56% of the Alberta distribution grid (as measured by circuit kilometres of line).
- FortisAlberta serves over 145 communities of which 135 are on standardized, individual franchise agreements. Substantially all have initial terms that expire between 2011 and 2013, and can be renewed for an additional five years upon mutual consent of the parties.
- FortisAlberta became an indirect, wholly owned subsidiary of Fortis on May 31, 2004, when Fortis acquired all the issued and outstanding shares of the company from an indirect wholly owned subsidiary of Aquila Inc.

Approximate Allocation of 2006 Revenue Requirement by Rate Class



FortisAlberta Inc.

Balance Sheet
($ millions)

	As at	For the year ended			As at	For the year ended	
Assets	Mar. 31, 2007	2006	2005	**Liabilities & Equity**	Mar. 31, 2007	2006	2005
Cash and short-term investments	3.2	-	1.8	Short-term debt	-	6.8	-
Acct. receivable	60.7	79.6	55.8	A/P + accr'ds/other	95.8	107.1	99.4
Income taxes receivable	8.8	8.3	-	Regulatory liabilities	5.7	7.5	2.2
Inventories and prepaids	17.7	13.5	17.0	Other liabilities	7.7	2.5	4.7
Current Assets	90.3	101.4	74.6	**Current Liabilities**	109.2	124.0	106.3
Net fixed assets	1,019.3	992.3	838.2	Deferred taxes/credits	257.4	262.1	288.1
L-T Materials & Supplies	28.4	22.2	13.4	Other liabilities	3.0	2.8	2.1
Regulatory deferral/deferred charges	55.1	60.6	10.6	Long-term debt	603.9	596.0	456.8
Future income tax	0.3	-	50.7	Total liabilities	973.4	984.9	853.3
Goodwill	189.3	189.3	189.3	Shareholders' equity	409.3	380.9	323.5
Total	1,382.7	1,365.8	1,176.8	**Total**	1,382.7	1,365.8	1,176.8

Ratio Analysis	12 mos. ended	For the year ended December 31				
Liquidity Ratios	Mar. 31, 2007	2006	2005	2004	2003	2002
Current ratio	0.83	0.82	0.70	0.62	0.55	0.60
Acc. Depreciation / Gross fixed assets	n.a.	21.9%	24.2%	24.7%	60.7%	64.1%
Cash flow / Total adjusted debt (1)	14.2%	13.4%	19.2%	20.0%	8.1%	14.3%
Total adjusted debt / EBITDA (1)	4.65	4.68	3.88	3.79	3.80	2.69
Cash flow / Capital expenditures	0.40	0.38	0.70	0.82	0.33	0.62
(Cash flow - Dividends) / Capital exp.	0.34	0.32	0.61	0.77	0.33	0.62
% debt in capital structure	59.6%	61.3%	58.5%	56.8%	57.6%	57.2%
% adjusted debt in capital structure (1)	60.8%	62.5%	60.1%	59.4%	59.0%	58.3%
Deemed equity	37.0%	37.0%	40.0%	40.0%	40.0%	40.0%
Common dividend payout (before extras.)	32.0%	33.8%	68.7%	24.5%	0.0%	1.3%
Coverage Ratios (1)						
EBIT interest coverage (times)	2.00	2.15	2.55	2.32	2.31	2.95
EBITDA interest coverage (times)	4.11	4.30	4.91	4.14	3.76	6.14
Fixed-charges coverage (times)	2.00	2.15	2.55	2.32	2.31	2.95
Profitability/Operating Efficiency						
EBIT margin	26.1%	26.6%	26.7%	28.9%	32.3%	29.3%
Net margin (before extras.)	17.4%	16.5%	7.3%	11.0%	12.5%	8.3%
Return on avg. common equity (bef. extras.)	11.1%	11.8%	5.6%	8.1%	8.8%	6.9%
Allowed ROE	8.51%	8.93%	9.60%	9.50%	9.50%	9.50%
GWh / FTE Employee	n.a.	16.4	16.9	17.7	17.7	17.8
Customers / FTE Employee	n.a.	475.1	485.2	513.4	509.6	507.4
Operating costs / Customer ($)	266.6	268.0	276.4	243.6	238.2	245.0
Mid-year rate base (net contributions, $ millions)	942.0 *f*	802.0	681.9	611.4	557.1	502.7

(1) Adjusted for operating leases
n.a. = not available
FTE = full-time equivalent
f: 2007 mid-year forecast

Note:
All figures are in Canadian dollars unless otherwise noted.

An S&P Report Discussing the Perceived Decline in Political Risk
Shining a Light on the Positive Outlooks for Ontario LDCs

STANDARD & POOR'S RatingsDirect

RESEARCH

Shining A Light On The Positive Outlooks For Ontario Electricity Distributors

Publication date: 26-Mar-2007
Primary Credit Analyst: Nicole Martin, Toronto (1) 416-507-2560; nicole_martin@standardandpoors.com

Standard & Poor's Ratings Services today revised the outlook to positive on all corporate credit and issue ratings on provincial and municipal government-owned local electricity distribution companies (LDCs) in the Province of Ontario (AA/Stable/A-1+). A Standard & Poor's rating outlook assesses the potential direction of a long-term issuer credit rating in the medium to long term. An outlook is not necessarily a precursor of a rating change.

Standard & Poor's examines the changing business environment for electricity distributors in Ontario, highlights its ratings methodology, and presents the terminology it uses to describe business and financial risk profiles and rank the utilities.

Which Issuers Are Affected?

The LDCs are Hamilton Utilities Corp. (A/Positive/--); Hydro One Inc. (A/Positive/--), Hydro Ottawa Holding Inc. (A-/Positive--); London Hydro Inc. (A-/Positive--); and Toronto Hydro Corp. (A-/Positive/--). The debt ratings on Borealis Infrastructure Trust – Enersource Bonds (A-/Positive) and Electricity Distributors Finance Corp. (EDFIN; A-/Positive) are also affected. The debt rating on the Borealis Enersource Bonds reflects the risk profile of Mississauga-based Enersource Corp. The debt rating on EDFIN reflects the risk profile of the least creditworthy of the three participants (listed in alphabetical order): Barrie Hydro Distribution Inc., EnWin Utilities Ltd., and PowerStream Inc. (For company credit specifics on each of the above rated entities, please see the research updates published earlier today on RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis.)

The positive outlooks on LDC Chatham Kent Energy Inc. (A-/Positive/--) and electricity generator Ontario Power Generation Inc. (OPG; BBB+/Positive/--) remain unchanged. The positive outlook on Chatham Kent Energy continues to reflect the positive outlook on its owner and guarantor the Municipality of Chatham-Kent (A-/Positive/--) and the expectation of a continued integrated and stable relationship between the shareholder and the utility. The September 2005 outlook revision on OPG reflects our expectation of improving financial and operational performance, continued stability in Ontario's plans for its wholly owned generator, and the promise of a new cost-of-service-plus-return regulatory framework for the bulk of its assets.

Four Key Credit Factors Support The Positive Trend

There is an observed trend of improvement, from a credit perspective, in the fundamental business conditions for LDCs in the Ontario market. Standard & Poor's believes four key factors, which we consider on a company-by-company basis, contribute to the lower business risk for Ontario's LDCs:

- An ongoing improvement in Ontario's regulatory process,
- A general shift away from LDC participation, and previously anticipated growth, in high-risk nonregulated activities,
- A meaningful period of stability for the Ontario market framework, with no plans for further market restructuring on the horizon that could affect credit quality, and
- A decreasing likelihood of privatization.

The current climate in the Ontario electricity sector is significantly different from four to five years ago when uncertainty ruled the day. Regulatory rate decisions had been delayed by government-imposed rate freezes, and LDCs were bearing the brunt of a growing variance between the actual price of electricity and what they were allowed to charge customers. The timely recovery of those cost variances was uncertain. Several utilities were actively engaged in growing high-risk nonregulated businesses as part of their portfolio holdings. The Ontario Energy Board's (OEB) governance, policies, and process were being revamped. There was still an expectation of some private equity participating in the wires sector despite the cancelled IPO of Hydro One. Since then, the rate freeze has been lifted, LDCs have recouped prudently incurred commodity costs and now flow through commodity costs to customers in a direct and timely manner. Several LDCs have since exited higher risk activities. There does not appear to be an appetite for further LDC-related market restructuring initiatives and there is little if any expectation of privatization. Rating changes in the sector during this time period are summarized in table 1.

Table 1

Ontario Electric Local Distribution Company Rating Actions

Company	2007	2006	2005	2004	2003	2002	2001	2000
Borealis Infrastructure Trust (Enersource)*	A-/Positive	N.C.	N.C.	A-	A-/Negative	A+/Watch Neg	AA-	N.R.
Chatham Kent Energy Inc.	N.C.	N.C.	A-/Positive/--	A-/Stable/--	N.R.	N.R.	N.R.	N.R.
Electricity Distributors Finance Corp.¶	A-/Positive	N.C.	A-	BBB+	BBB+/Negative	A-/Watch Neg	N.R.	N.R.
Hamilton Utilities Corp.	A/Positive/--	N.C.	N.C.	N.C.	A/Stable/--	A+/Watch Neg/--	N.R.	N.R.
Hydro One Inc.	A/Positive/A-1	N.C.	A/Stable/A-1	A/Stable/A-2	A-/Negative/A-2	A/Watch Neg/A-1	N.C.	AA-/Stable/A-1+
Hydro Ottawa Holding Inc.	A-/Positive/--	N.C.	A-/Stable/--	N.R.	N.R.	A/Watch Neg/--	N.R.	N.R.
London Hydro Inc.	A-/Positive/--	N.C.	N.C.	A-/Stable/--	A-/Negative/--	A-/Watch Neg/--	N.R.	N.R.
Toronto Hydro Corp.	A-/Positive/--	N.C.	N.C.	A-/Stable/--	A-/Negative/--	A/Watch Neg/--	N.R.	N.R.

*C$290 mil. 6.27% Borealis-Enersource bonds series TRANCHE 1 due 05/03/2011. ¶C$175 mil. 6.45% unsecured debentures series 2002-1 due 08/15/2012. N.C.--No change. N.R.--Not rated.

Ontario's Regulatory Process Continues To Improve

The stability, transparency, consistency, and timeliness of the Ontario regulatory regime and framework have been steadily improving as a result of ongoing amendments to the Ontario Energy Board Act. The Ontario Energy Board's (OEB) Cost of Capital review, was completed in late 2006, resulting in minimal changes to the regulatory methodology previously approved by the OEB in 1998. The OEB's decision to maintain its 1998 formula for determining ROEs allowed for in the rate-setting process, while disappointing for equityholders and not likely to encourage privatization, is another example of stability and consistency. It also removed significant uncertainty that had been hanging over the sector in 2006 as a result of OEB staff proposals to significantly lower equity risk premiums.

There is now improved clarity regarding the methodology and timing of upcoming rate decisions. The number of recently completed overarching regulatory decisions supports our expectation of ongoing improvement in timeliness. The OEB's 2nd Generation Incentive Regulation Mechanism and Licence Amendment Proceeding were also resolved in 2006. The regulatory calendar for the next two years is set, the regulator's workflow 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.

Utility Holding Companies Move Away From Higher Risk Activities

After targeting material growth in cash flow generation from nonregulated high-risk activities such as energy retailing and telecommunications, LDCs are returning their strategic focus back to what they know best--the core business of owning and operating low-risk monopoly wires operations. This change in focus is concurrent with an upcoming period of regulated infrastructure investment in the province, illustrated in the case of the LDCs by Ontario's C$1 billion smart meter initiative. The LDCs rated by Standard & Poor's are viewed as having the wherewithal and financial capacity to manage the risks involved in the smart meter rollout. Nevertheless, LDCs will face a challenge in the upcoming years as they implement this major initiative. How the smart meters will fit with existing customer billing systems and whether substantial upgrades to, or replacement of, existing back office systems will be required remains unknown at this stage and, as a result, heightens potential operating and financial risks for LDCs.

Some LDCs continue to be either interested or involved in power generation but most are taking a more conservative approach than contemplated a few years ago. Power generation projects in Ontario are generally supported by long-term contracts with manageable commodity risk and creditworthy government counterparties. Furthermore, interested LDCs are contemplating minor equity positions or joining a joint venture, thus limiting their risk exposure.

Ontario LDC Market Role Appears Set For Now

From an LDC's perspective, the evolution of a more stable Ontario market framework began in early 2004 and we do not anticipate a change in this positive trend in the foreseeable future. Standard & Poor's is not aware of any further market restructuring initiatives that would affect LDC credit quality. Solidifying our view of continued stability in the legal and regulatory market framework for Ontario LDCs is the current government focus on facilitating a decade's worth of necessary major capital investment in generation and transmission in the province.

The relatively low-risk role of the LDC in Ontario's electricity marketplace is to deliver and bill consumers for electricity. Furthermore, LDCs have no obligation to ensure adequate electricity supply for their customers as the Ontario Power Authority fulfills this function. As such, the utilities face limited financial risk related to commodity price and volume variability.

Government Ownership Continues To Dominate Ontario LDC Sector

Contrary to previous expectations, there has been no substantial shift away from government utility ownership in the province. It is almost 10 years since the Electricity Act launched Ontario's market restructuring efforts and yet almost all Ontario LDCs remain entirely government-owned. Anticipated mergers and acquisitions in the sector and related operational efficiency have not been forthcoming.

Our ratings are currently based on the stand-alone credit quality of the LDCs. This approach to LDC rating assessments was based on the anticipated (partial or complete) divestiture by municipalities of their wholly owned utilities. In the next 12 months, we expect to complete an in-depth review of the relationships between each utility and its municipal owner. We will also explore the ability (legal and financial) and the inclination, if any, of each municipality to support its wholly owned utility.

In 2005 we reexamined the relationship between the Province of Ontario and two of its wholly-owned electricity-related entities (Hydro One and OPG) with a resulting incorporation of one and two notches of support in the respective ratings. Nonetheless, the relationship between these two entities and the province is a key part of our analysis and undergoes regular reviews. (Please see " Credit FAQ: Implied Government Support As A Rating Factor For Hydro One Inc. And Ontario Power Generation Inc.", published Oct. 20, 2005, on RatingsDirect.)

Rating Methodology

We start the rating process with a detailed assessment of the utility's business risk exposure, followed by a critical analysis of its financial strengths and weaknesses. For regulated entities the analysis of business risk includes consideration of the consistency and predictability, efficiency and timeliness, balance, clarity, and independence of the regulatory framework. We view forward-looking cash flow strength, as measured by cash flow debt and interest coverage, as a key ingredient of the financial risk profile assessment. Nevertheless, neither historical nor our own forward-looking cash flow metrics predetermine the final rating outcome.

Two companies with similar financial risk profiles will be rated very differently if their business challenges and prospects differ. Standard & Poor's developed the matrix in table 2 to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. The table illustrates the relationship of business and financial risk profiles to the issuer credit rating and provides context for our terminology. For a more detailed explanation, please see " A Closer Look At Industrials Ratings Methodology" published Nov. 13, 2006, on RatingsDirect. Table 5, at the end of this article, lists other related articles.

Table 2

Business Risk/Financial Risk Matrix

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

Business Risk Profiles

Standard & Poor's categorizes business risk profiles from "excellent" to "vulnerable" (see table 2). Ontario LDC business risk profiles all fall in the "strong" category (see table 3). As we review each LDC in more detail during the next 12 months, business conditions may improve sufficiently to warrant a shift in individual LDC business risk profiles toward the upper portion of the "strong" category and the lower bounds of the "excellent" category. Table 3 ranks the Ontario LDCs by corporate credit rating and outlook, and then by relative credit strength within the same rating and outlook profile.

Table 3

Local Distribution Company Business Profiles

Electric Utilities and Generation

As of March 26, 2007

Issuers	**Corporate credit rating**	**Business risk**	**Financial risk**
Hydro One Inc.	A/Positive/A-1	Strong	Intermediate
Hamilton Utilities Corp. (HUC)	A/Positive/--	Strong	Intermediate
Toronto Hydro Corp.	A-/Positive/--	Strong	Intermediate
London Hydro Inc. (LHI)	A-/Positive/--	Strong	Intermediate
Hydro Ottawa Holding Inc. (HOHI)	A-/Positive/--	Strong	Intermediate
Borealis Infrastructure Trust's Borealis-Enersource series bonds*	A-/Positive	Strong	Intermediate
Electricity Distributors Finance (EDFIN) Corp.*	A-/Positive	Strong	Intermediate
Chatham Kent Energy Inc. (CK Energy)	A-/Positive/--	Strong	Intermediate

*Debt rating.

Financial Risk Profiles

We do not anticipate substantial changes to the affected companies' financial risk profiles, which, although intermediate, are typically very stable. The OEB Cost of Capital decision to apply a consistent deemed capital structure across all LDCs will, on average, hurt regulated cash flow generation of the smaller LDCs but is not expected to affect ratings. The OEB has indicated that it will apply a deemed capital structure of 60% debt (that now will also include 4% short-term debt)and 40% equity for the purpose of determining utility revenue requirements for all Ontario LDCs (see table 4 for previous deemed capital structure). We understand the OEB's rationale for applying uniform capital structures and agree that the smaller size of an LDC does not necessarily imply higher regulatory, market, or competitive risk in the context of a regulated monopoly. The decision also aligns the methodology used for electricity distributors with that used for gas distributors in Ontario and is an example of the OEB's deliberate move toward uniformity across the two sectors. The change in ratemaking assumptions is being implemented in an orderly and gradual manner, allowing utilities time to adapt.

Table 4

Ontario Energy Board Cost Of Capital Methodology

	Deemed Capital Structure			
	Previously		Cost of Capital Decision*	
Utility's Rate Base	**Debt¶ (%)**	**Equity (%)**	**Debt§ (%)**	**Equity (%)**
C$250 million - C$1.0 billion	60	40	60	40
C$100 million - C$250 million	55	45	60	40
< C$100 million	50	50	60	40

*As of Dec. 20, 2006. ¶Long-term debt only. §The 60% includes 56% long-term debt and 4% short-term debt. The board has determined that the cost of deemed short-term debt rate will be calculated as the average of the three-month bankers' acceptance rate plus a fixed spread of 25 basis points.

Several of these LDCs have more conservative consolidated financial policies than that deemed by the regulator. Generally, a decision to materially lever up an LDC's (or its holding company's) actual balance sheet to the regulatory deemed debt levels would have more of a negative impact on cash flow strength and could affect ratings. Within Standard & Poor's rated universe the OEB's uniform capital structure decision will influence the net revenue of Chatham Kent Energy, London Hydro, and some of the EDFIN participants.

A More Settled Future For Ontario's LDCs

The expectation of ongoing improvement in LDC business risk profiles is largely a result of steadily increasing clarity and stability with regards to regulatory methodology and timetables. The continued absence of further market restructuring and political involvement in the regulatory process should further bolster business risk profiles. An expectation of continued government ownership and less aggressive growth targets for unregulated activities also contributes to the improving business profiles but to a lesser extent. Continued improvement in the business environment could, but will not necessarily result in any further positive rating actions.

Related Articles

Table 5

Related Articles

Title	Publication date
Utility Statistical Methodology	Jan. 22, 2007
A Closer Look At Industrials Ratings Methodology	Nov. 13, 2006
Utility Comparative Ratio Analysis--Long-Term Debt, U.S.	Oct. 2, 2006
Creditstats: 55101010 Electric Utilities--Canada	Sept. 29, 2006
Corporate Ratings Criteria--Rating Methodology: Industrials & Utilities; Cyclicality; Loan Covenants; Country Risk	June 9, 2005
Comparing Utility Regulatory Regimes Around the World	July 8, 2004

EBIT Interest Coverage

	EBIT Interest Coverage				
	2002	**2003**	**2004**	**2005**	**2006**
AltaLink L.P.	2.6	2.4	2.5	2.7	2.3
CU Inc.	2.8	3.0	2.8	2.7	2.4
Enersource Corp. [2]	1.7	1.7	1.9	2.1	2.0
ENMAX Corp.	13.3	16.5	13.4	9.4	7.7
EPCOR Utilities Inc.	2.9	2.4	2.9	3.1	2.9
FortisAlberta Inc.	3.0	2.3	2.3	2.6	2.2
FortisBC Inc.	1.8	2.0	2.4	2.2	2.1
Hydro One Inc.	2.5	3.0	3.2	3.3	3.0
Hydro Ottawa Holding Inc.	1.9	1.4	1.6	2.7	3.6
Maritime Electric	2.3	2.5	2.4	2.5	2.5
Newfoundland Power	2.6	2.4	2.5	2.3	2.3
Nova Scotia Power	2.3	2.8	3.0	2.6	3.1
Toronto Hydro	2.1	2.9	2.3	2.3	2.4
Veridian Corp. [2/]	1.9	2.2	2.5	3.1	3.5
Median	**2.4**	**2.4**	**2.5**	**2.6**	**2.5**

Notes:

Altalink: Source: DBRS; excludes inter-company loans; 2002 and 2003 are 12 months ending April 2003 and April 2004 respectively. Year-end changed from April to December in 2004

CU Inc: Source: DBRS; 2006 is 12 months through September

Enersource, ENMAX, FortisAlberta, FortisBC, Newfoundland Power, Toronto Hydro: Source: DBRS

EPCOR: Source: DBRS for 2002 and 2003; 2004-2006 calculated from annual reports

Hydro One: Source: DBRS 2002-2005; 2006 calculated from AR using DBRS method

Hydro Ottawa: Source: DBRS 2002-2005; 2006 calculated from annual report

Maritime Electric: S&P 2002-2005; 2006 calculated from annual report

Nova Scotia Power: DBRS: 2002-2005; 2006 calculated from AR using DBRS method

Veridian: Source: DBRS 2002-2005; 2006 calculated from AR using DBRS method