Q. Referring to Schedule I, please provide the referenced source document for this schedule and any updates.

A. Please see the attached. There have been no updates to this document.

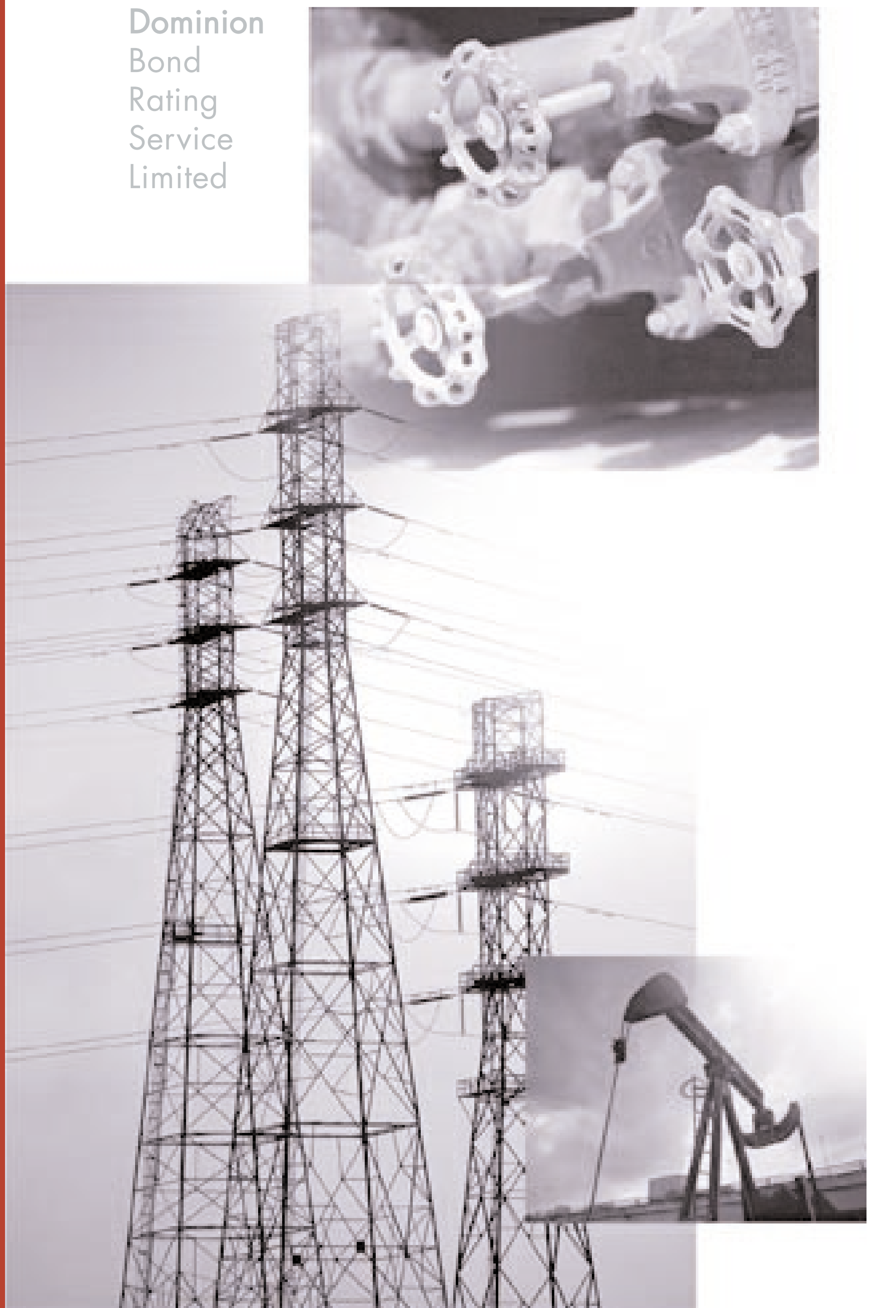
PUB-73 NLH
Attachment

The Canadian Electricty Industry in 2002

Industry Study

Energy

Dominion
Bond
Rating
Service
Limited



FEBRUARY 2003

MATTHEW KOLODZIE, CFA

GENEVIEVE LAVALLEE, CFA

WALTER SCHROEDER, CFA

NIGEL HEATH, CFA

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Companies Included in the Study

AltaLink, L.P.
Aquila Networks Canada (Alberta) Ltd.
Aquila Networks Canada (British Columbia) Ltd.
Brilliant Power Funding Corporation
British Columbia Hydro & Power Authority
Bruce Power Limited Partnership
Canadian Utilities Limited
Churchill Falls (Labrador) Corporation Limited
CU Inc.
Electricity Distributors Finance Corporation
Emera Inc.
Enersource Corporation
ENMAX Corporation
EPCOR Utilities Inc.
Fortis Inc.
Great Lakes Power Inc.
Hydro One Inc.
Hydro Ottawa Holding Inc.
Hydro-Québec
The Manitoba Hydro Electric Board
New Brunswick Power Corporation
Newfoundland and Labrador Hydro
Newfoundland Power Inc.
Nova Scotia Power Inc.
Ontario Power Generation Inc.
Saskatchewan Power Corporation
Toronto Hydro Corporation
TransAlta Corporation
TransAlta Utilities Corporation
Veridian Corporation

Government-Owned and Guaranteed Integrated Electric Utilities

Issuer	B.C. Hydro	Sask. Power	Manitoba Hydro	Hydro Quebec	N.B. Power	Nfld. & Lab Hydro	Churchchill Falls	Group Average
Year ended/12 months ended	Sept. 30 2002	June 30 2002	June 30 2002	Sept. 30 2002	Mar. 31 2002	Dec. 31 2001	Dec. 31 2001	
Current Rating								
Commercial paper	R-1 (middle)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-2 (high)		
Long-term debt	AA (low)	"A"	"A"	"A"	"A"	BBB	"A"	
Financial Ratios								
% adjusted debt in the capital structure	81.8%	59.0%	83.0%	72.9%	105.2%	68.2%	43.3%	**73.3%**
Cash flow/adjusted total debt (1)	0.09	0.15	0.07	0.09	0.08	0.03	0.14	**0.09**
Cash flow/capex (1)	1.05	1.18	0.94	1.53	1.67	0.39	8.63	**2.20**
Average coupon on long-tern debt (2)	6.80%	8.66%	8.17%	8.05%	8.06%	8.07%	7.70%	**7.93%**
Common dividend payout (before extras.)	46.8%	n/a	n/a	30.9%	0.0%	99.8%	56.3%	
Coverage Ratios								
EBITDA coverage	2.22	2.63	1.82	2.41	1.95	1.72	2.06	**2.12**
EBIT coverage	1.49	1.59	1.31	1.69	1.20	1.39	1.60	**1.47**
Fixed-charges coverage	1.49	1.59	1.31	1.69	1.20	1.39	1.60	**1.47**
Earnings Quality								
Net earnings before extras. ($ millions)	235	106	176	1,793	39	53	22	
Operating margin	17.5%	22.9%	40.1%	34.3%	21.7%	37.1%	37.0%	**30.1%**
Net margin (before extras.)	5.6%	9.5%	11.9%	13.8%	3.0%	16.4%	23.6%	**12.0%**
Return on avg. common equity (before extras.)	14.4%	9.2%	13.5%	12.5%	nmf	9.4%	6.3%	**10.9%**
% of profit returned to government	n/a	57.8%	57.3%	n/a	55.6%	99.8%	63.5%	**66.8%**
Key Operating Statistics								Total
Total assets ($ millions)	12,061	3,575	10,261	58,461	3,236	1,935	654	
Gross electricity revenues ($ millions)	4,160	1,111	1,278	11,324	1,278	324	94	
Electricity sold (millions of kWh)	n/a	n/a	n/a	n/a	19,059	8,341	32,361	
Capacity (MW) (3)	11,102	2,880	5,185	31,172	3,769	1,601	5,653	**61,362**

(1) For OPG, cash flow is net of nuclear waste funding. (2) Average coupon rate reported for all companies is for year ended December 31, 2001.

(3) For OPG, includes laid-up 2,060 MW at Pickering A; for Churchill Falls, includes the 225 MW capacity of Twin Falls

	Investor-Owned/Non-Government Guaranteed Generation and Integrated Electric Utilities								Parent Holding Companies (consolidated)		
Issuer	Aquila Networks Canadian (B.C.)	CU Inc.	TransAlta Utilities	Great Lakes Power	Nova Scotia Power	EPCOR Utilities	Ont. Power Generation	Group Average	EMERA Inc.	TransAlta Corp.	Canadian Utilities
Year ended/12 months ended	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002	Mar. 31 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002		Sept. 30 2002	Sept. 30 2002	Sept. 30 2002
Current Rating											
Commercial paper		R-1 (low)		R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)			R-1 (low), Neg.	R-1 (low)
Long-term debt	BBB (high)	A (high)	A (low)	BBB (high)	A (low)	A (low)	A (low), Neg.		BBB (high)	BBB (high), Neg.	"A"
Financial Ratios											
% adjusted debt in the capital structure	55.6%	55.0%	54.7%	47.1%	58.9%	61.0%	38.3%	**52.9%**	62.3%	52.0%	56.2%
Cash flow/adjusted total debt	0.14	0.18	0.15	0.12	0.12	0.20	0.45	**0.19**	0.11	0.17	0.18
Cash flow/capex	0.47	1.28	1.66	4.20	1.68	1.22	0.65	**1.59**	1.75	0.46	0.92
Average coupon on long-tern debt (1)	8.15%	8.41%	7.25%	n/a	7.59%	9.14%	5.79%	**7.72%**	7.50%	6.95%	8.09%
Common dividend payout (before extras.)	46.1%	109.2%	275.4%	44.2%	188.7%	50.1%	430.2%	**nmf**	81.5%	93.1%	40.5%
Coverage Ratios											
EBITDA coverage	3.03	4.04	6.85	3.16	3.14	3.99	5.36	**4.22**	2.97	3.14	4.23
EBIT coverage	2.34	2.79	4.89	2.80	2.18	2.83	1.37	**2.74**	1.94	1.89	2.99
Fixed-charges coverage	2.34	2.56	2.24	2.80	1.87	2.67	1.37	**2.26**	1.75	1.63	2.60
Earnings Quality											
Net earnings (before extras., after prefs.) ($ millions)	19	162	142	137	87	196	63	**nmf**	103	143	237
Operating margin	24.3%	20.9%	33.1%	59.1%	28.4%	14.8%	4.4%	**26.4%**	23.0%	18.4%	20.9%
Net margin (before extras., after prefs.)	12.2%	8.1%	18.9%	33.1%	10.2%	6.7%	1.0%	**12.9%**	8.3%	8.4%	8.9%
Return on avg. common equity (bef. extras., after prefs.)	11.7%	12.3%	16.0%	11.3%	8.9%	15.6%	1.2%	**11.0%**	8.7%	6.2%	14.3%
Approved ROE	9.50%	n/a	10.18%	n/a	10.75%	n/a	n/a	**nmf**	n/a	10.2%	n/a
Key Operating Statistics								Total			
Total assets ($ millions)	429	3,737	3,676	3,430	2,860	4,634	17,008		3,909	7,397	5,523
Total electricity revenues (2) ($ millions)	154	1,331	751	278	846	1,217	6,044		1,161	1,715	1,340
Electricity sold (3) (millions of kWh)	2,834	10,234	29,664	5,845	11,100	24,644	128,800		na	45,369	14,568
Capacity (MW)	188	1,162	4,519	1,042	2,183	1,881	24,168	**10,975**	2,183	7,528	1,960

(1) For Nova Scotia Power, average coupon is at December 31, 2001. (2) CU Inc./Canadian Utilities: includes non-electricity operations; EPCOR, net of power purchased for retail marketing purposes. (3) CU Inc.: distribution volume throughputs; EPCOR: sales of self-generated electricity only

Electricity Transmission and Distribution Companies

Issuer	Altalink L.P. (1)	Aquila Networks Canada (Alberta)	Enersource Corp.	ENMAX Corp	Hydro One	Hydro Ottawa (2)	Nfld. Power	Toronto Hydro	Veridian Corp.	Group Average	Holding: FORTIS Inc. (3)
Year ended/12 months ended	Oct. 31 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002	Sept. 30 2002		Sept. 30 2002
Current Rating											
Commercial paper		R-1 (low)		R-1 (low)	R-1 (low)			R-1 (low)			
Long-term debt	A (high)	"A"	A (low)	A (low)	"A", Neg.	A (low)	"A"	A (low)	A (low)		BBB (high)
Financial Ratios											
% adj. debt in the capital structure	59.9%	59.0%	62.3%	16.5%	57.1%	55.4%	54.8%	65.4%	57.8%	**54.2%**	60.6%
Cash flow/adjusted total debt	0.08	0.17	0.08	1.55	0.13	0.14	0.18	0.03	n/a	**0.30**	0.12
Cash flow/capex	1.10	0.70	0.73	2.06	1.11	0.79	1.00	0.26	n/a	**0.97**	0.65
Average coupon on long-tern debt	n/a	n/a	6.29%	7.57%	7.82%	6.90%	n/a	6.80%	7.60%	**7.16%**	8.60%
Common dividend payout (before extras.)	56.0%	0.0%	0.0%	21.3%	57.1%	0.0%	41.5%	0.0%	0.0%	**19.5%**	47.3%
Coverage Ratios											
EBITDA coverage	3.76	5.78	2.42	13.36	3.59	4.69	4.06	3.14	2.36	**4.80**	3.38
EBIT coverage	2.14	3.05	0.97	11.27	2.50	2.10	2.75	1.19	0.85	**2.98**	2.46
Fixed-charges coverage	2.14	3.05	0.97	11.27	2.31	2.10	2.64	1.19	0.85	**2.95**	2.29
Earnings Quality											
Net earnings (before extras., after prefs.) ($ millions)	16.9	25.1	-2.6	164.0	322.0	7.6	27.5	7.1	-3.8	**nmf**	59
Operating margin	41.8%	32.2%	21.9%	41.3%	42.1%	20.9%	46.3%	18.0%	16.5%	**31.2%**	24.7%
Net margin (before extras.)	19.1%	9.8%	-3.5%	31.3%	14.6%	11.0%	18.0%	1.2%	-3.6%	**nmf**	9.7%
Return on avg. common equity (before extras.)	4.9%	8.3%	-1.4%	17.7%	8.6%	4.1%	10.6%	0.7%	-1.6%	**nmf**	12.8%
Approved ROE (4)	9.75%	n/a	6.60%	n/a	9.88%	6.60%	9.05%	6.60%	6.60%	**nmf**	n/a
Key Operating Statistics											
Total assets ($ millions)	903	872	642	1,315	11,874	554	679	2,489	202		1,861
Net electricity revenues ($ millions)	75	250	66	447	2,204	68	159	383	29		601
Electricity sold (millions kWh) (5)	n/a	23,563	7,566	9,678	26,700	5,646	4,720	26,423	2,385		6,805

(1) Six months ended October 31, 2002. (2) Nine months ended September 30, 2002. Power costs include fuel costs.
(3) Consolidated. (4) Approved ROE for Hydro One is for transmission only. (5) Distribution throughputs only for Hydro One.

The Canadian Electricity Industry in 2002

The Canadian electricity industry experienced a significant shakeup in 2002 as the Ontario government intervened in the Ontario electricity restructuring process on a number of occasions and essentially brought the restructuring process to a stop. The most significant interventions occurred in the spring of 2002 when the privatization of Hydro One Inc. ("Hydro One") was halted, and on November 11, 2002, when the provincial government announced various measures to reduce the cost of electricity to consumers.

On November 11, 2002, the Ontario government introduced an electricity price freeze and caps on distribution and transmission rates, to be in effect until at least 2006. These measures were largely a result of the spike up in wholesale electricity prices during the July 2002 to September 2002 period to an average monthly high of 7.52¢/kWh in September 2002.

Two factors accounted for the price spikes: (1) high demand due to unusually hot weather; and (2) capacity constraints, in part due to the failure to return to service Unit 4 of Pickering A as originally scheduled. Since September 2002, wholesale prices have come down to an average price of 4.9¢/kWh in November, but back up to around 5.63¢/kWh in December. Interestingly, generation and transmission operations in Ontario will be the least affected by the measures introduced, while distribution and retail marketing will be the hardest hit although the Ontario government has since introduced various regulations easing the impact of some of the measures initially introduced.

The actions by the Ontario government have increased the level of uncertainty going forward for existing market participants and future potential participants in the Ontario electricity market.

DBRS expects that once the 2,000 MW of laid-up nuclear capacity expected to come back on line in the summer of 2003 (515 MW at Pickering A's unit 4 and 1,500 MW from 2 units at Bruce A) actually begins production, the on-peak prices will decline from what was experienced in 2002. The additional low-cost supply should stabilize the average price of electricity in the range of 4.0¢ to 4.5¢/kWh. In addition, approximately 1,500 MW of nuclear capacity from the remaining three laid-up units of Pickering A are expected to be returned to service in 2004 and 2005, which will contribute to a greater degree of stability in electricity prices in Ontario over the medium term.

Once sufficient capacity is added/returned to service in order to stabilize electricity prices and the next provincial election is over, DBRS believes it is likely that the provincial government will resume the electricity restructuring process. However, the restructuring process may be altered, depending on the political party in power at the time.

Aside from the volatility in Ontario, electricity markets in the rest of Canada remained relatively stable. Following a number of minor problems in Alberta when it first opened its electricity market to retail competition on January 1, 2001, the market in that province now appears to be functioning properly. Alberta's wholesale electricity rates rose sharply prior to retail market competition on January 1, 2001, but then fell sharply in mid-2001 as demand management kicked in and new supply came online. Rates in 2002 are averaging much below those in 2001 at just over 4¢/kWh.

Elsewhere is Canada, restructuring of electricity markets is proceeding slowly. The governments of British Columbia, Manitoba, Québec, and New Brunswick have all implemented or announced the restructuring of their crown-owned electricity utilities into separate operating units. However, New Brunswick has gone one step further by announcing that four new independent subsidiaries will be created from New Brunswick Power Corporation ("NB Power") and each will be required to: (1) earn a positive rate of return on equity; (2) pay a cash dividend to the Province; (3) pay appropriate income and capital taxes; and (4) borrow funds without a provincial government guarantee. The government of Newfoundland and Labrador is currently considering various options for the future of the electricity industry in that province.

As a result of the experiences in Alberta and Ontario, it is unlikely than many other provinces will introduce any major restructuring processes over the near term. However, most provinces have taken steps to provide open access to their transmission systems. Doing so is consistent with the Federal Energy Regulatory Commission ("FERC") directives in the United States. As such, the U.S. market will continue to offer opportunities for electric utilities that operate in provinces with significant inter-tie connections with the U.S., especially given the establishment of Regional Transmission Organizations (RTOs). RTOs will reduce the costs of exporting as they will charge customers only one transmission charge for electricity transmitted within the territory served by the RTO. All public utilities that own, operate, or control electric transmission assets in the U.S. must have (1) open access transmission tariffs in place, and (2) a regional transmission planning process (to join or form an RTO) in effect by September 30, 2003. The risk is that the U.S. market will become saturated given the significant amount of new supply being built or planned, which would put downward pressure on prices and limit the earnings growth potential of the U.S. market.

Over the longer term, electric utilities in Canada and in the U.S. will likely face increasing costs related to environmental concerns. The trend is towards tighter environmental standards, which, for coal-based generators in particular, will result in higher costs to meet the new standards.

UNIQUENESS OF ELECTRICITY AS A COMMODITY

Electricity has certain characteristics that make it unique from other commodities:

- The most important characteristic differentiating it from other commodities is the inability to store electricity (with the exception of hydro power with water storage, which is essentially the ability to store potential generation). Basically, when electricity is generated, it must be consumed immediately
- The overall cost structure for generating electricity is heavily weighted on fixed costs, given the high capital intensity of building generation
- A high fixed-cost structure encourages discounting when excess supply exists, particularly when the variable cost of the fuel is very low (such as with nuclear and hydro power)
- Demand is sensitive to temperatures and is seasonal with peaks in winter (heating) and summer (air conditioning)
- Supply is sensitive to rainfall, especially in Canada where over 60% of generation comes from hydro
- The transmission grid in each jurisdiction is a major determinant of electricity prices in that jurisdiction
  - The lower the interconnection capacity, the more dependent the price of electricity on supply/demand conditions in that particular jurisdiction
- When new generation capacity comes on line in a competitive market, it is usually in large chunks which can potentially result in significantly reduced electricity prices until demand increases sufficiently to eliminate the excess supply
- Electricity prices vary from region to region, unlike other commodities that are based on one uniform price (i.e., gold and copper)

KEY TRENDS AND CHARACTERISTICS IN THE CANADIAN ELECTRICITY INDUSTRY

- Limited long-term growth for electricity demand (approximately 1% per year)
- Weather is a significant factor that influences electricity demand and supply in Canada
- Gas-based generation is becoming increasingly more expensive, but will continue to grow in importance
- Impact of the Kyoto Protocol will be greatest on coal-based generation
- Despite environmental concerns, coal-based generation expected to remain in place due to its low production cost (coal is a relatively inexpensive fuel)
- Churchill Falls remains the lowest cost hydro electricity generation site in the world, and it may be expanded
- Transmission interconnections are primarily north-south between Canada and the United States, and interconnection growth expected to be north-south as well
- Canadian electricity industry remains dominated by government-owned utilities, and is not expected to change
- Alberta electricity restructuring considered successful, despite initial problems
- Ontario electricity restructuring in turmoil from political intervention, but will likely be resumed after the next provincial election and once a sufficient amount of the laid-up nuclear capacity comes back on line
- Electricity industry restructuring continues slowly in other jurisdictions apart from Alberta and Ontario
- Canadian electric utilities are cost competitive with U.S. electric utilities

Limited long-term growth in electricity demand:

- Long-term demand growth expected be about 1% per year
- While growth in electricity demand is driven to a certain degree by economic growth and population growth, the primary driver is the electricity consumption of selective industries
- Mining (especially aluminum and nickel), forestry (newsprint), chemicals, and steel rank as most electricity-intensive industries
- High economic growth regions like Alberta and the Greater Toronto Area will also likely continue to experience strong growth in electricity demand

Weather is a significant factor that influences electricity supply and demand:

- Reflecting the extreme temperature changes in this country, weather is one of the most significant factors that influences the demand for and supply of electricity in Canada
- Temperatures in the winter and summer months influence the demand for heating and air conditioning, respectively
- Electricity is the primary source of heating in provinces such as Newfoundland and Québec, and most installed air conditioners are electrically powered
- The Canadian climate, which is made up of cooler winters and warmer summers, increases the seasonal peak demand and overall consumption of electricity
- Global warming is also increasing the volatility in electricity demand in various jurisdictions
- Certain provinces like Ontario are now recording dual electricity demand peaks, namely summer peaks that are equal to or higher than winter peaks. For example, Ontario hit a record peak demand of nearly 25,500 MW on August 1, 2002 as a result of an unusually warm summer in Ontario and increased air conditioning usage
- On the supply side, with hydro-based generation accounting for over half of total installed generation in Canada, the amount of precipitation is an important factor influencing the total amount of electricity that can be generated in a given region

- Generation in British Columbia, Manitoba, Ontario, and Québec is highly influenced by the amount of precipitation
- Higher rainfall levels in a given watershed will result in more runoff available for hydro generation
- Similarly, a greater amount of snowfall in the winter months results in higher seasonal snow pack levels, which translates to more spring runoff available for generation
- Storage capacity is a key factor for hydroelectric generation as most of the demand for electricity in Canada is during the winter and summer months, while rainfall is greatest in the spring. Hence, jurisdictions with substantial storage capacity can benefit from lower-cost hydro-power during periods of high demand but poor precipitation

Gas-based generation is becoming increasingly more expensive, but will continue to grow in importance:

- Gas production in the U.S. has been limited to near roughly 52 billion cubic feet a day, while production in Canada has not risen much above 17 billion cubic feet a day
- High production decline rates and aging gas fields are the reasons for the lack of growth in production
- In Canada, the remoteness of gas reserves, connection difficulties, and the short drilling season (winter months) lengthen the time needed to bring reserves to market
- Little growth in production combined with continued growth in demand for gas will keep prices higher
- Despite higher gas prices plus transportations costs (close to $1.45/mcf to deliver to Ontario, for example, or close to 30% of wellhead prices for gas), most new generation capacity being built is fueled by natural gas
- Most new gas-based generation is currently being used as peaking plants due to higher fuel costs relative to average electricity prices across Canada
- Over the longer term, as gas-based generation grows in importance in certain provinces like Alberta and eventually Ontario, the cost of gas-based generation will become the marginal price setter for electricity in these provinces
- Ongoing higher gas prices will result in higher electricity prices in certain jurisdictions over time
- Gas from the arctic and liquefied natural gas (LNG) are long-term solutions to rising gas prices (as gas prices rise, LNG becomes a more economical alternative)

Impact of the Kyoto Protocol will be greatest on coal-based generation:

- Coal-based and oil-based generation is expected to be the hardest hit by the ratification of the Kyoto Protocol
- Gas-based generation will also be impacted, but it is expected to be to a much lesser degree
- Hydro and nuclear generation will be the least impacted by Kyoto
- For regulated companies, net impact of Kyoto should be minimal as it is expected that regulators will permit the companies to recover the additional environmental costs from ratepayers
- For companies whose power is sold pursuant to Power Purchase Arrangements (PPAs) in Alberta, the change of law provision should allow them to pass through the additional costs to the holders of the Power Purchase Arrangements
  - Therefore, it will be the holders of the Power Purchase Arrangements that will be directly impacted by the higher costs
- Companies that have merchant coal-based or oil-based generation will be directly hit by the higher environmental costs
- It remains to be seen how long Canada can take a tough stand on Kyoto (raising Canada's energy costs) while the U.S. chooses not to participate

Despite environmental concerns, coal-based generation expected to remain in place:

- Coal-based generation remains significant in Alberta, Saskatchewan, Ontario, Nova Scotia, and New Brunswick
- Existing coal-based generation currently provides low cost, base load power
- Operating and maintenance costs plus fuel costs for coal-based generation are currently in the 2½¢ to 3¢/kWh range compared to the cost of greenfield gas-based generation of about 6½¢/kWh in Ontario (the cost declines the closer the plant is to gas fields – due to lower transportation costs)
- As coal-based plants reach the end of their useful lives, it is expected that they will be replaced by gas-based generation due to the increasing environmental costs associated with coal, especially given the signing of the Kyoto Protocol
- However, coal plants that have a number of years remaining in service, are unlikely to be converted to gas due to the high costs to complete the conversion
- For example, to convert Ontario's approximately 30 billion kWh/year of coal-based generation to greenfield gas, it would cost about $900 million to $1,200 million annually in higher electricity costs

Churchill Falls remains the lowest-cost hydro electricity generation site in the world, and it may be expanded:

- Churchill Falls has an installed capacity of 5,428 MW and consistently generates at least 30 billion kWh/year of electricity at a variable cost of 0.10¢/kWh and a total cost of 0.20¢/kWh (includes depreciation)
- Almost all of the power is bought by Hydro-Québec under a very favourable long-term contract
- While negotiations between the provincial governments (those of Québec, and Newfoundland and Labrador) in respect of the development of the lower Churchill River (the Gull Island project) have stalled once again, this plant remains a potentially large source (over 2,000 MW) of inexpensive electricity
- While the cost of electricity from this project would not be as low as that from the current installed capacity, the cost would still remain very competitive

Transmission interconnections are primarily north-south and interconnection capacity growth expected to be north-south as well:

- In most Canadian provinces, transmission interconnections are north-south with the U.S. rather than east-west with other provinces
- There are limited east-west interconnections in Canada, with the exception of Ontario and Québec, partly due to the low density of the population base that makes it uneconomic
- New Brunswick and Manitoba have the highest proportion of their generation capacity interconnected, while Québec and Ontario have the highest absolute interconnection capacity with neighbouring jurisdictions
- There continues to be a shortage of transmission interconnections in Canada, and this is unlikely to change quickly
- New interconnections are proceeding slowly and will continue to be built north-south as electricity industry restructuring continues in the U.S.
- An additional 1,000 MW of export capacity and 500 MW of import capacity between Ontario and Michigan was added recently through the installation of three phase-shifting transformers and an autotransformer
- An additional 1,250 MW interconnection between Ontario and Québec has been postponed, with the capacity not expected to be available until 2007
- Manitoba is installing a 230 kV line into North Dakota
- Public opposition to the construction of transmission lines is the primary reason for slow development in interconnections, and this attitude is unlikely to change soon
- FERC efforts to create larger transmission grids in the U.S. are a positive to Canadian electricity generators as they will be able to transmit electricity even further south and with lower tariff costs

Canadian electricity industry remains dominated by government-owned utilities, and is not expected to change:

- Only three provinces, Alberta, Nova Scotia, and Prince Edward Island, do not have provincially owned electric utilities
- Electricity generation, transmission and distribution in the remaining provinces is dominated by provincially-owned electric utilities
- Only one province, Nova Scotia, has managed to successfully privatize its electric utility Nova Scotia Power Inc. ("Nova Scotia Power")
- Two other provinces, Newfoundland and Labrador, and Ontario, have tried to privatize but to date, have not been successful
- Given the dominance of low-cost, hydro-based generation in many of the provinces and the strong attachment by the populace to low-cost power, it makes it very difficult politically to successfully privatize electric utilities or even restructure the electricity industry
- Alberta and Ontario are the only provinces that have tried to restructure their electricity markets, and the experiences have been mixed
- These experiences, in addition to the problems experienced in California, have reduced many provincial governments' interest in restructuring or privatizing
- However, two provinces, British Columbia and New Brunswick, remain committed to a limited restructuring process

Alberta electricity restructuring considered successful, despite initial problems:

- In Alberta, the wholesale market was opened to competition in April 1999 (large industrial customers were permitted to purchase directly from the Alberta Power Pool), almost two years earlier than when retail competition was introduced
- In the second half of 2000, the combination of several years of lack of new capacity, strong electricity demand, and high natural gas prices resulted in very high electricity prices, with average monthly spot prices ramping up from 5.2¢/kWh in May 2000 to 25.3¢/kWh in October 2000

- Given the high spot prices and that a competitive retail market was to begin on January 1, 2001, the Alberta government intervened by:
  - Announcing that the cost of power deferral accounts accumulated in 2000 would be recovered through customer rates over a three-year period beginning in 2002 rather than the normal one-year period following the end of the year in question; and
  - Imposing a price cap on Regulated Rate Option customers
- The Regulated Rate Option was available for a period of three to five years following retail market opening (residential, farm and small commercial) for customers who chose not to sign retail contracts
- The provincial government allowed those companies offering the Regulated Rate Option to accumulate (in a deferral account for recovery over a two-year period beginning in 2002) the difference between the fixed price paid by consumers and the price paid by company for the commodity
- The price cap imposed for Regulated Rate Option customers was set at 11¢/kWh for 2001, much higher than the cap imposed in Ontario, but still much below the average spot price recorded in Alberta in November 2000 of 22.7¢/kWh. Spot electricity prices remained relatively high (in the range of 10¢ to 13¢/kWh) for the first four months of 2001 following the opening of the Alberta market to retail competition. Since that time, the market has worked as it should with the combination of new generation capacity and demand management resulting in a decline in average electricity prices over the latter part of 2001 to about 3¢ to 5¢/kWh and remained in that range until November 2002
- Electricity prices in Alberta moved higher in November 2002 and December 2002 to about 7.0¢/kWh, which was not unexpected given the higher demand during the winter months
- Temporary price caps helped stabilize the situation without completely derailing the industry restructuring process
- Alberta will probably be used as a model for future restructuring in Canada

Ontario electricity restructuring in turmoil from political intervention, but will likely be resumed after the next provincial election and once a sufficient amount of the laid-up nuclear capacity comes back on line:

- The Ontario government has intervened in the Ontario electricity restructuring process on a number of occasions since the summer of 2001
- The most significant intervention occurred on November 11, 2002 when the provincial government announced various measures to reduce the cost of electricity to consumers
- The actions by the Ontario government with respect to the electricity market have resulted in a loss of confidence in the government's ability to manage market restructuring and have increased the level of uncertainty going forward for existing market participants and future potential participants
- The electricity price freeze and the caps on distribution and transmission rates introduced on November 11 and in effect until at least 2006 were largely a result of the spike up in electricity prices during the July 2002 to September 2002 period to an average monthly high of 7.52¢/kWh in September 2002
- The timing of the price spike and consumers' reaction to the higher prices was not very good given the timing of the next provincial election, which could be as early as the spring of 2003
- Two factors accounted for the price spikes: high demand due to unusually hot weather; and capacity constraints, in part due to the failure to return to service Unit 4 of Pickering A as originally scheduled
- Since September, wholesale prices have come down to an average price of 4.9¢/kWh in November, but back up to around 6.59¢/kWh in December
- Once the roughly 2,000 MW of laid-up nuclear capacity expected to come back on line (515 MW at Pickering A's unit 4 and 1,538 MW from 2 units at Bruce A) and the 650 MW Sarnia Regional Cogeneration plant begins production by mid 2003, on-peak prices should decline from what was experienced in 2002
- The additional low-cost supply should stabilize the average price of electricity in the range of 4.0¢ to 4.5¢/kWh
- An additional 1,545 MW of nuclear capacity from the remaining three units of Pickering A expected to come back on line in 2004 and 2005, plus an additional 580 MW from the Brighton Beach Cogeneration plant in Windsor is expected to be commissioned in mid-2004
- Once sufficient capacity is added/returned to service in order to stabilize electricity prices and once the next provincial election is over, it is likely that the provincial government will resume the electricity restructuring process
- However, the restructuring process may be altered, depending on the political party in power at the time

Electricity industry restructuring continues slowly in other jurisdictions apart from Alberta and Ontario:

- Aside from Alberta and Ontario, the move towards industry restructuring has been limited

<table>
<tr><th>Jurisdiction</th><th>Industry Restructuring</th></tr>
<tr><td>British Columbia</td><td>• British Columbia Hydro & Power Authority (“BC Hydro,” regulated and fully integrated utility) is a Crown corporation, wholly owned by the provincial government
• In April 2002, BC Hydro began operating under three separate lines of business: (1) Generation; (2) Transmission; and (3) Distribution, as well as three service groups: (1) Field Services; (2) Engineering Services; and (3) Shared Services.
• In November 2002, the B.C. government announced its new Energy Plan. Key objectives include: (1) Increase investment in the energy sector; (2) Maintain low-cost power; (3) No nuclear generation; (4) Retain public ownership of the BC Hydro generation, transmission and distribution assets; and (5) the formation of a new Crown corporation, BC Hydro Transmission Corp., which will operate the transmission grid
• No further market restructuring is anticipated in British Columbia</td></tr>
<tr><td>Saskatchewan</td><td>• Saskatchewan Power Corporation (“SaskPower,” regulated and fully integrated utility) is a Crown corporation, wholly owned by the provincial government
• SaskPower posted an Open Access Transmission Tariff that became effective on January 1, 2002, which has opened the provincial transmission system to wholesale energy suppliers and users. This allows wholesale customers to procure power in the competitive market and allows independent power producers to export power
• There are currently no plans for further restructuring or deregulation of the market in Saskatchewan</td></tr>
<tr><td>Manitoba</td><td>• The Manitoba Hydro Electric Board (“Manitoba Hydro,” regulated and fully integrated utility) is a Crown corporation, wholly owned by the provincial government
• Currently no plans for deregulation or market restructuring as it is believed that Manitoba prices would likely increase from their current low levels</td></tr>
<tr><td>Québec</td><td>• Hydro-Québec (regulated and fully integrated utility) is a Crown corporation wholly owned by the provincial government
• Hydro-Québec’s transmission and distribution operations are regulated by the Province of Québec’s Régie de l’énergie
• In 2000, the provincial government amended the Act respecting the Régie de l’énergie, which included: (1) The clarification of the deregulation of generation (it removed electricity generation from the Régie’s jurisdiction). While generation remains unregulated, Hydro-Québec retains sole responsibility for developing hydro sites with a capacity of over 50 MW; and (2) The establishment of a heritage electricity pool for Québec consumers. For Hydro-Québec, it means that the generator must supply the distributor with a maximum of 165,000 GWh/year for Québec customers at a set price of 2.79¢/KWh. The Régie has essentially granted a monopoly to Hydro-Québec, as domestic sales are currently just over 152,000 GWh/year. The Act also introduced competition to the wholesale market for all needs in excess of the heritage pool. The wholesale market had already been open to competition since May 1, 1997. However, none of the ten municipal distributors has exercised the option to date given the low cost of power offered by Hydro-Québec
• There are no plans currently to introduce retail competition</td></tr>
<tr><td>New Brunswick</td><td>• NB Power (regulated and fully integrated utility), a Crown corporation wholly owned by the provincial government, will be restructured on April 1, 2003 into four separate entities, each with its own capital structure: (1) a Generation company, (2) a Nuclear company, (3) a Transmission company, and (4) a Distribution and Customer Services company.
• Market will be restructured on April 1, 2003, as follows:
– Distribution utilities (wholesale customers) and large industrial (retail) customers will be permitted to procure power in the competitive markets
– Generators will be permitted to sell by contract to eligible customers inside and outside the province
– Non-discriminatory access to the transmission system
• Periodic review of market developments will determine how quickly the province will move towards full retail competition</td></tr>
<tr><td>Nova Scotia</td><td>• Nova Scotia Power was privatized in August 1992, and is wholly owned by Emera Inc.
• Currently no plans for deregulation or market restructuring</td></tr>
<tr><td>Newfoundland and Labrador</td><td>• Newfoundland and Labrador Hydro (“NLH,” regulated generation) is a Crown corporation wholly owned by the provincial government
• Newfoundland Power Inc. (“Newfoundland Power”, regulated distribution and transmission) is wholly owned by Fortis Inc.
• Provincial government currently reviewing options for the future of the electricity industry</td></tr>
<tr><td>Prince Edward Island</td><td>• Maritime Electric (regulated transmission and distribution) wholly owned by Fortis Inc.
• Currently no plans for deregulation or market restructuring</td></tr>
</table>

Canadian utilities remain cost competitive with U.S. utilities

- Average unit electricity costs (generation, transmission, and distribution), excluding income taxes, across Canada in 2001 were about:
  - Cdn3.70¢/kWh in Alberta (for coal-based generation);
  - Cdn4.40¢/kWh in Manitoba;
  - Cdn5.10¢/kWh in Ontario (for customers whose distributor is Hydro One);
  - Cdn5.40¢/kWh in Québec (includes power from Churchill Falls);
  - Cdn5.80¢/kWh in Newfoundland;
  - Cdn5.80¢/kWh in British Columbia;
  - Cdn6.50¢/kWh in Saskatchewan;
  - Cdn6.50¢/kWh in Nova Scotia; and
  - Cdn6.72¢/kWh in New Brunswick

- Average unit retail prices for residential consumers in 2001 were as follows across Canada:
  - Cdn6.03¢/kWh in Manitoba;
  - Cdn6.13¢/kWh in British Columbia;
  - Cdn6.16¢/kWh in Québec;
  - Cdn7.90¢/kWh in Newfoundland;
  - Cdn8.04¢/kWh in New Brunswick;
  - Cdn8.0¢ to 10.0¢/kWh in Ontario (following market opening, unit retail prices increased by about 1.0¢ per kWh);
  - Cdn9.23¢/kWh in Saskatchewan;
  - Cdn9.64¢/kWh in Nova Scotia; and
  - about Cdn17.0¢/kWh in Alberta, although it has since come down to around Cdn12.0¢/kWh

- Average unit costs of electricity and unit retail prices in Canada are generally competitive with those in the U.S., especially when the foreign exchange impact is taken into account.
  - U.S. prices near US7.0¢/kWh are equal to about Cdn11.0¢/kWh

- Some of the key reasons for the lower average unit costs and retail prices in Canada are:
  - dominance of low-cost, hydro-based generation;
  - dominance of government-owned utilities, which do not pay income taxes and do not necessarily have the same profit motives as investor-owned utilities

- Part of the benefit of no income taxes, however, is offset by the high leverage of government-owned utilities and the resulting higher interest costs

Comparison of Ontario and Alberta – The Two provinces that have restructured their electricity markets

Issues	Ontario	Alberta
Franchise area	Population of around 12 million, accounting for approximately 38% of Canada's population. Ontario accounts for about 42% of Canada's real GDP.	Population of just over 3 million, accounting for 10% of Canada's population. Alberta accounts for about 12% of Canada's real GDP and is Canada's richest province.
Dominant market participants	Ontario Power Generation Inc. ("OPG") is the key generation company; Bruce Power and Great Lakes Power are the other prominent generation companies in Ontario; remaining generation comprised of isolated independent power producers (IPPs). Hydro One is the primary transmission company; Great Lakes Power Inc. ("Great Lakes Power") has a small amount of transmission in northern Ontario. Distribution is very fragmented with 95 distribution companies providing the service, including Hydro One, Toronto Hydro Corporation ("Toronto Hydro"), Enersource Corporation ("Enersource"), Hydro Ottawa Holding Inc. ("Hydro Ottawa") and Hamilton Utilities. The electricity retail market, while currently in a state of uncertainty, is comprised of a number of players; key participants include Direct Energy and EPCOR Utilities Inc. ("EPCOR Utilities")	TransAlta Utilities Corporation ("TransAlta"), ATCO/Canadian Utilities Limited and EPCOR Utilities Inc. are the key generation companies in Alberta; remaining generation composed of IPPs. AltaLink is the dominant transmission company, with Canadian Utilities, EPCOR Utilities, and ENMAX Corporation ("ENMAX") also having transmission capacity. Distribution is much more concentrated in Alberta; key participants include Canadian Utilities, EPCOR Utilities, ENMAX, and Aquila Networks Canada (Alberta). Electricity retail market is composed of many participants, but is relatively concentrated at the residential and small commercial and industrial level; key participants serving the residential and small commercial and industrial classes include EPCOR Utilities, ENMAX, IQ2 Power Corp., Gibson Energy, and Direct Energy.
Installed in-service capacity	Approximately 27,750 MW at the end of 2002, comprised of 22,169 MW from OPG, 3,140 MW from Bruce Power and 2,440 MW from a combination of Great Lakes Power and IPPs.	Approximately 10,900 MW at the end of 2002; composed of 7,200 MW under the legislatively mandated long-term Power Purchase Arrangements and about 3,700 MW from IPPs.
Initial experience with restructuring	The restructuring process included opening both wholesale and retail markets to competition at the same time. Market opening delayed from November 1, 2000 to May 1, 2002 as it was indicated by various entities that stakeholders would not be ready by the original date. The electricity market opened to competition on May 1, 2002 with prices remaining low until July when prices spiked up due to (1) high demand caused by unusually hot weather; and (2) capacity constraints, in part due to the failure to return to service Unit 4 of Pickering A as originally scheduled. Average monthly spot price peaked at 7.52¢/kWh in September 2002. Provincial government intervened in November 2002 as a result of price spikes and public pressure. Timing of the upcoming provincial elections expected in spring of 2003 was likely also a factor that led to political intervention.	The restructuring process included the opening of wholesale market to competition in April 1999 and the opening of the retail market to competition and the initiation of long-term Power Purchase Arrangements on January 1, 2001. Wholesale power prices increased significantly during second half of 2000. The Provincial government intervened in November 2000 as a result of very high electricity prices (averaged 25.3¢/kWh in October 2000). The provincial elections, which were anticipated to occur in 2001, likely also encouraged political intervention.

<table>
<tr><th>Issues</th><th>Ontario</th><th>Alberta</th></tr>
<tr><td>History of average monthly spot prices (¢/kWh)</td><td>Average monthly prices (¢/kWh)
<table>
<tr><th></th><th>2002</th></tr>
<tr><td>Jan.</td><td>-</td></tr>
<tr><td>Feb.</td><td>-</td></tr>
<tr><td>Mar.</td><td>-</td></tr>
<tr><td>Apr.</td><td>-</td></tr>
<tr><td>May</td><td>2.92</td></tr>
<tr><td>Jun.</td><td>3.51</td></tr>
<tr><td>Jul.</td><td>5.82</td></tr>
<tr><td>Aug.</td><td>6.42</td></tr>
<tr><td>Sept.</td><td>7.52</td></tr>
<tr><td>Oct.</td><td>4.80</td></tr>
<tr><td>Nov.</td><td>4.94</td></tr>
<tr><td>Dec.</td><td>5.63</td></tr>
<tr><td>Avg.</td><td>5.20</td></tr>
</table>
Average prices in Ontario were very low just after market opening when demand was low. An unusually hot summer and capacity constraints caused prices to rise sharply in July, August, and September of 2002.
Prices fell back down in October and November as demand declined.
Prices will trend upwards again in the colder winter months of January and February, and will likely drop down to the 3.0¢/kWh to 4.0¢/kWh range during the shoulder months of March through June.</td><td>Average monthly prices (¢/kWh)
<table>
<tr><th></th><th>2000</th><th>2001</th><th>2002</th></tr>
<tr><td>Jan.</td><td>4.65</td><td>13.12</td><td>2.84</td></tr>
<tr><td>Feb.</td><td>4.71</td><td>11.68</td><td>2.24</td></tr>
<tr><td>Mar.</td><td>7.72</td><td>9.72</td><td>5.51</td></tr>
<tr><td>Apr.</td><td>9.37</td><td>11.48</td><td>4.50</td></tr>
<tr><td>May</td><td>5.17</td><td>8.83</td><td>4.04</td></tr>
<tr><td>Jun.</td><td>10.67</td><td>6.36</td><td>4.62</td></tr>
<tr><td>Jul.</td><td>12.41</td><td>5.35</td><td>2.64</td></tr>
<tr><td>Aug.</td><td>20.21</td><td>5.24</td><td>3.20</td></tr>
<tr><td>Sept.</td><td>17.63</td><td>2.99</td><td>4.57</td></tr>
<tr><td>Oct.</td><td>25.33</td><td>4.39</td><td>4.44</td></tr>
<tr><td>Nov.</td><td>22.77</td><td>3.33</td><td>6.91</td></tr>
<tr><td>Dec.</td><td>18.89</td><td>3.37</td><td>7.09</td></tr>
<tr><td>Avg.</td><td>13.29</td><td>7.16</td><td>4.38</td></tr>
</table>
Alberta's wholesale electricity prices rose sharply prior to retail market competition, but then fell as new supply came on stream and demand management kicked in. Prices in 2002 are averaging much below those in 2001. Volatility of prices in Alberta is higher than Ontario because transmission interconnection capacity with adjacent jurisdictions is limited.</td></tr>
<tr><td>Degree of political intervention</td><td>Ontario government has intervened since the summer of 2001 on a number of occasions.
Most significant intervention occurred in November 2002 when the government froze the price of electricity at 4.3¢/kWh for almost all customer classes and capped transmission and distribution rates at current levels.</td><td>Alberta government intervened in November 2000, before the start of retail competition on January 1, 2001.
Government (1) announced that the cost of power deferral accounts accumulated in 2000 would be recovered through customer rates over a three-year period beginning in 2002 rather than the normal one-year period following the end of the year in question; and (2) imposed a price cap of 11¢/kWh on Regulated Rate Option (residential, farm and small commercial) customers starting January 1, 2001. The government allowed those companies offering the Regulated Rate Option to accumulate (in a deferral account for recovery over a two-year period beginning in 2002) the difference between the fixed price paid by consumers and the price paid by company for the commodity. The price under the Regulated Rate Option has subsequently reduced to 6.1¢/kWh for 2002.</td></tr>
<tr><td>Impact of political intervention</td><td>The November 2002 government intervention has essentially halted the electricity restructuring process until at least 2006.
OPG, through the market power mitigation agreement, and the provincial government will be funding the difference between wholesale prices and the fixed 4.3¢/kWh retail prices.
The generation sector has not been directly impacted by the political intervention, but it remains unclear as to how new generation and the wholesale market will develop.</td><td>The electricity market restructuring process was not halted and the market was allowed to continue to develop.
New capacity was built, which combined with demand management as a result of the high prices, resulted in a reduction in average electricity prices to more normal, sustainable levels in the range of 3¢ to 5¢/kWh.
After some initial difficulties, the open market appears to be functioning effectively.</td></tr>
</table>

Issues	Ontario	Alberta
Future generation capacity	3,500 MW of laid-up nuclear capacity expected to be brought back on line during the 2003 to 2005 period. New generation capacity beyond that will likely be gas-based or from renewable sources.	New generation will be predominantly gas-based. Gas reserves in Alberta make for easy generation capacity additions.
Cost of greenfield generation capacity	Current generation capacity in Ontario is a good mix of coal, nuclear, hydro and gas/oil, and is generally low cost – around 4.0¢/kWh all-in. New capacity beyond nuclear refurbishment will be gas, which costs about 6½¢/kWh based on current gas and transportation costs (DBRS estimate).	Given the proximity to gas in Alberta, cost of greenfield gas generation is about 5¢/kWh.
Outlook for electricity prices	Average electricity prices expected to stabilize in the 4.0¢ to 4.5¢/kWh range once all of the 3,500 MW of laid-up nuclear capacity comes back on line. The new capacity should be sufficient to meet five to ten years' worth of growth in demand.	Average electricity prices expected to increase somewhat over time as most of the new generation has been or will be gas based, which is more expensive than coal, the dominant source of generation in Alberta. The cost of implementing Kyoto on coal generation is unknown.
Outlook for electricity market	The key variable for Ontario electricity prices to stabilize in the 4.0¢ to 4.5¢/kWh range is the approximately 2,000 MW of anticipated laid-up nuclear generation expected to return to service in the summer of 2003. This could be sufficient for the provincial government to reverse some of the measures implemented in the legislation passed in December 2002, especially those imposed on distributors. If the provincial government does not alter the legislation until 2006, as currently intended, the electricity market will likely remain much the same as it is today.	Restructuring of the electricity market in Alberta has produced the outcome anticipated when a market is subject to competitive forces. The initial high prices resulted in demand management and new generation capacity, which in turn resulted in a reduction in average prices in the 3¢ to 5¢/kWh range. As the supply/demand situation tightens due to increased demand related to weather or reduced supply form generation outages, prices increase in response. However, as the situation reverses, prices decline in response.

Electricity Markets in Canada

BRITISH COLUMBIA

Characteristics of the British Columbia Market

- In 2002, the British Columbia market hit a peak demand of 8,692 MW, a decrease of 3.4% from the peak demand of 8,995 MW reached in 2001, which was a historical high
- Electricity sales in British Columbia in F2002 were approximately 71.5 billion kWh
- British Columbia currently has a total installed capacity of about 11,100 MW (includes independent power projects and other non-utility generation), composed of the following:

Fuel Source	Percentage	Capacity
Hydro	90.2%	10,009 MW
Natural gas	8.2%	912 MW
Other	1.6%	181 MW
Total		**11,102 MW**

Note: Capacity shown in table is for BC Hydro only.

- Note that with high hydro generation, load factors are low (typically in the 50% to 60% range)

- British Columbia's current interconnection capacity is equivalent to about 39% (export capacity) of installed capacity, and consists of:
  - 1,200 MW from British Columbia to Alberta, and 1,000 MW from Alberta to British Columbia
  - 3,150 MW from British Columbia to the U.S., and 2,000 MW from the U.S. to British Columbia

- Two vertically integrated utility companies exist in British Columbia:
  - British Columbia Hydro and Power Authority, a Crown corporation; and
  - Aquila Networks Canada (British Columbia) Ltd. ("ANCBC")
- BC Hydro provides distribution services to approximately 94% of electricity customers in B.C. and ANCBC serves most of the remainder of the province, except for certain large industrial customers and a few local areas and municipalities
- BC Hydro owns over 80% of the provincial generating capacity (11,102 MW) and accounts for approximately 90% of electricity production
- The remaining generating capacity is owned by:
  - The Columbia Power Corporation ("CPC") – a Crown corporation with the primary mandate to undertake power project investments as the agent of the Province on a joint venture basis with the Columbia Basin Trust (325 MW currently in service and 480 MW under development)
  - ANCBC owns 205 MW of hydro generation
  - Island Cogeneration LP operates a 245 MW cogeneration facility on Vancouver Island
  - Large industrial companies such as Alcan, Teck Cominco
  - Approximately 40 other industrial self-generators and independent power producers

- Substantial interconnection capacity, along with an extensive hydro base with storage capability, provides BC Hydro with the ability to profit from energy trading and maintain low rates to customers:
  - BC Hydro is able to import low-cost electricity during off-peak periods to satisfy its customer requirements while reducing its own generation and storing water at its dams
  - During higher-priced on-peak periods, domestic generation is stepped up as the stored water is released, and any excess above provincial requirements is exported

- Electricity rates in British Columbia are among the lowest in North America
- BC Hydro rates have been frozen since 1996, and have not changed or undergone a public review since 1993

- The British Columbia Power Exchange Corporation ("Powerex"), is a wholly owned electricity trading subsidiary of BC Hydro:
  - Powerex buys, sells, and exchanges electricity in the electricity trade marketplace and purchases electricity for BC Hydro's domestic use
  - Powerex's trade arena extends from Manitoba in western-central Canada to California and Nevada in the southwestern United States
  - Key trading partners include utilities, large industrial customers, cogenerators, independent power producers, and marketers

- Since 1997, BC Hydro has had in place an open access wholesale transmission tariff (WTS):
  - Using WTS, IPPs located within British Columbia may sell wholesale electricity to wholesale purchasers such as BC Hydro, Powerex, ANCBC, or municipal utilities, or to other power markets
- Since 1996, BC Hydro's annual exports have increased from 2,427 million kWh to a peak of 23,900 million kWh in F2001
- Electricity export volume depends on the amount of rainfall, and lately has been adversely affected by very dry conditions

Regulation in British Columbia

BC Hydro is regulated by the British Columbia Utilities Commission (“BCUC”), and both entities are subject to general or special directions issued by order of the Province of British Columbia. Orders in Council from the Province establish the basis for determining customer rates, allowed rates of return, calculation of revenue requirements, and the annual payment to the Province. The approved ROE is set at a rate equivalent to the pre-tax return allowed for investor-owned utilities regulated under the Utilities Commission Act. BC Hydro’s approved pre-tax ROE for 2002 is 15.24% (versus 16.59% in 2001), which is determined after taking into account any available amount from the Rate Stabilization Account. A Rate Stabilization Account (RSA) has been established, whereby transfers are made to the RSA during high-income years to reduce the need for rate increases in lower income years.

Average annual electricity rate increases are limited to the projected rate of inflation for British Columbia plus two percentage points. However, the Province initiated a rate freeze as of December 10, 1997, which was to continue until March 31, 2000, but has been extended to March 31, 2003. Rates have not increased since 1993, and the rate structure is under review by government.

BC Hydro is required to make annual payments to the Province equal to 85% of its “distributable surplus” (largely net income before capitalized charges and transfers), provided BC Hydro’s debt-to-equity ratio after deducting the payment does not exceed 80/20.

ANCBC is also subject to regulation by the BCUC. ANCBC’s ROE is linked to the forecast long-term Government of Canada bond yield. As a regulated utility, the Company’s balance sheet is maintained with a 60%/40% debt/equity structure. ANCBC’s electricity rate increases are set each year to achieve the approved ROE. For 2002, the BCUC approved an ROE of 9.80% (compared to 9.75% in 2001 and 10.0% in 2000).

In mid-1996, the Company was the first electric utility in Canada to operate under incentive-based regulation, known as Performance Based Regulation (PBR), compared to the traditional cost-of-service method for determining rates. The initial PBR agreement was for a three-year period from 1996-1998, and was subsequently extended to 2000. Again in December 1999, the BCUC approved extension of the PBR agreement for another three-year period (2000-2002).

The PBR provides the Company with incentives for improving operating efficiencies with a 50%/50% sharing of savings between ANCBC and its customers. The current PBR allows for a 2% productivity improvement factor each year (on operating, maintenance and capital expenditures). General rate increases are capped at 5% per year. In addition, the PBR allows the Company to flow through approved capital expenditures to its rate base.

In March 2000, the Company also became the first utility to receive the BCUC’s approval to allow up to 10% of its industrial and wholesale customers (representing about 40% of ANCBC’s total electrical load) to choose an alternative electricity supplier.

The Reorganization of BC Hydro

- In April 2002, the Utility began operating under three separate lines of business: (1) Generation; (2) Transmission; and (3) Distribution, as well as three service groups: (1) Field Services; (2) Engineering Services; and (3) Shared Services.

The New Energy Plan and Outlook for the British Columbia Market

- In November 2002, the B.C. government announced its new Energy Plan. Key objectives include:
  - Increase investment in the energy sector
  - Maintain low-cost power
  - No nuclear generation
  - Retain public ownership of BC Hydro generation, transmission, and distribution assets
  - The formation of a new Crown corporation, BC Hydro Transmission Corp., which will operate the transmission grid
- No further market restructuring is anticipated in British Columbia
- Low-cost, hydro-based generation capacity and significant interconnection will continue to benefit BC Hydro in the export markets
- The existing rate freeze will end on March 31, 2003, and the BCUC will hold a revenue requirements hearing by the end of F2004 with the expectation to move to performance-based regulation and negotiated settlements
- The market for independent power producers will become more favourable:
  - BC Hydro will be restricted to improvements at existing plants
  - New generation projects will be developed by the private sector
  - Improving open access to BC Hydro’s transmission system will enable IPPs to participate in U.S. wholesale markets
  - However, IPPs are limited by the fact that they will not be allowed to supply domestic residential and small commercial customers; these customers will continue to be supplied by BC Hydro
- Annual load growth over the medium term is expected to be in the 1.5% to 2.0% range

ALBERTA

Characteristics of the Alberta Market

- In 2002, the Alberta market hit a peak demand of 8,570 MW on December 3, 2002, an increase of 8.0% over the peak demand of 7,934 MW reached in 2001
- As at November 30, 2002, the province had total installed capacity of about 10,900 MW (includes independent power projects and other non-utility generation), composed of the following:

Fuel Source	Percentage	Capacity
Coal	50.5%	5,500 MW
Gas	39.4%	4,300 MW
Hydro and other renewables	10.1%	1,100 MW
Total		**10,900 MW**

- Despite the size of Alberta's electricity market, it has limited interconnections:
  - 1,000 MW from Alberta to British Columbia, and 1,200 MW from British Columbia to Alberta; and
  - 150 MW with Saskatchewan
- The Alberta/Saskatchewan border is the dividing line for the east and west synchronization divisions in North America, and electricity interchange across this dividing line is difficult
- The major generators include:
  - TransAlta Corporation with 4,369 MW (utility) and 396 MW (independent power projects);
  - ATCO/Canadian Utilities Limited with 1,162 MW (utility) and 396 MW (independent power projects) currently in service and 321 MW (independent power projects) expected to be fully operational shortly;
  - EPCOR Utilities with 1,701 MW (utility) and 180 MW (independent power projects)
- The major holders of transmission assets in Alberta include:
  - AltaLink L.P.;
  - Canadian Utilities Limited;
  - EPCOR Utilities; and
  - ENMAX Corporation
- The primary electricity distributors in Alberta include:
  - Canadian Utilities Limited;
  - EPCOR Utilities;
  - ENMAX Corporation; and
  - Aquila Networks Canada (Alberta)
- TransAlta Corporation is a non-regulated electric generation and marketing company, with generation plants in Canada, the U.S. and Mexico. The Company owns and operates about 40% of the total capacity currently available to the Alberta market (held largely by a wholly owned subsidiary TransAlta Utilities Corporation), with most of the assets subject to legislated mandated long-term Power Purchase Arrangements (PPAs)
- Canadian Utilities Limited is a holding company whose principal operating subsidiaries include regulated electric and gas transmission and distribution utilities, as well as electricity generation assets in Alberta that are subject to legislatively mandated long-term PPAs (all held by wholly owed subsidiary CU Inc.), in addition to non-regulated subsidiaries and holdings in England, Australia, and Canada. ATCO Ltd. owns 52% of Canadian Utilities Limited
- ENMAX Corporation is a holding company whose primary operating subsidiaries include: (1) ENMAX Power Corporation, a regulated entity that transmits and distributes electricity in Calgary, Alberta, and the surrounding area. (2) ENMAX Energy Corporation, a non-regulated entity that markets electricity and natural gas to over 400,000 customers in Calgary, Red Deer, Lethbridge, and several other smaller communities in Alberta. ENMAX is wholly owned by the City of Calgary
- EPCOR Utilities Inc. is a holding company with ownership in various regulated and non-regulated operating subsidiaries, including: (1) The regulated EPCOR Power group of companies, which generate, transmit, and distribute electricity, and EPCOR Water Services Inc - water purification and distribution operations. (2) Non-regulated independent power plants in Alberta, B.C., and Washington; retail energy services including natural gas, electricity, and water heaters; and retail energy marketing. EPCOR Utilities is wholly owned by the City of Edmonton
- Aquila Networks Canada (Alberta) Ltd. is involved exclusively in electricity distribution in Alberta. Its franchise region is located in central and southern Alberta
- AltaLink L.P. was established to own and operate the regulated transmission assets in Alberta acquired from TransAlta Utilities on April 29, 2002

Current Market Environment

Key features of the current competitive environment, which came into effect January 1, 2001, include:

- *Retail Competition,* allowing for the implementation of independent, negotiated arrangements. Large industrial customers have been permitted to purchase directly from the Alberta Power Pool since April 1, 1999. With the implementation of retail competition, retail marketing businesses now bear the price risk associated with electricity commodity prices. A utility's exposure to price risk is mitigated for those customers who choose the Regulated Rate Option. This option is available for five years for residential and farm customers (to the end of 2005), and for three years for small commercial and small industrial customers (to the end of 2003)

- *Transmission and distribution operations* remain regulated activities, with transmission operated on a shared cost basis. These operations will continue to be subject to regulatory hearings in the absence of negotiated settlements
- *Cost recovery of existing generation in service at December 1995 will continue under the long-term Power Purchase Arrangements.* The PPAs incorporate annually adjusted, formula-based ROEs, consisting of a fixed 450 basis point risk premium above forecast ten-year Government of Canada bond yields, with minimum ROEs set for certain plants near the end of their useful lives to ensure that operating risks are adequately compensated for. The PPAs also incorporate incentives that encourage operating efficiencies. Deemed equity for most of the generation assets under the PPAs has been set at 45%. All benefits and risks associated with meeting efficiency targets are borne by the generator
- *New generation assets (those in service after December 1995)* are excluded from the cost recovery process and pricing is market based. All new gas generation added falls in this category

Results to Date of Industry Restructuring in Alberta

- Electricity industry restructuring in Alberta is the most advanced in Canada
- Following a number of minor problems in the beginning, the electricity market appears to be functioning properly
- Alberta's wholesale electricity rates rose sharply prior to retail market competition, but then fell sharply in mid-2001 as demand management kicked in and new supply came on stream. Rates in 2002 averaged much below those in 2001
- The following table provides the average monthly electricity prices experienced in Alberta since the beginning of 2000

Average Monthly Prices (¢/kWh)

	2000	2001	2002
Jan.	4.65	13.12	2.84
Feb.	4.71	11.68	2.24
Mar.	7.72	9.72	5.51
Apr.	9.37	11.48	4.50
May	5.17	8.83	4.04
Jun.	10.67	6.36	4.62
Jul.	12.41	5.35	2.64
Aug.	20.21	5.24	3.20
Sept.	17.63	2.99	4.57
Oct.	25.33	4.39	4.44
Nov.	22.77	3.33	6.91
Dec.	18.89	3.37	7.09
Avg.	13.29	7.16	4.38

- Key factors for the increase in prices starting in mid-2000 include:
  - capacity constraints;
  - strong economic growth; and
  - high natural gas prices, given the high percentage of gas-generation in the province at the time (just under 40%)
- As a result of surging wholesale prices in late 2000, the Alberta government intervened in the electricity market. The government:
  - announced that the cost of power deferral accounts accumulated in 2000 would be recovered through customer rates over a three-year period beginning in 2002 rather than the normal one-year period following the end of the year in question; and
  - imposed a price cap of 11¢/kWh on Regulated Rate Option (residential, farm and small commercial) customers starting January 1, 2001
- The government allowed those companies offering the Regulated Rate Option to accumulate in a deferral account for recovery over a two-year period beginning in 2002, the difference between the fixed price paid by consumers and the price paid by company for the commodity
- The price under the Regulated Rate Option declined to 6.1¢/kWh in 2002
- For companies having generation assets subject to PPAs, the results to date have demonstrated the risks that exist under this regime
- An important risk highlighted by DBRS is establishing who is at fault and defining "*force majeure*" in the event of an unplanned shutdown
- The TransAlta Utilities case with its Wabamum Unit 4 outage has proven the difficulty associated with defining force majeure. At the end of May 2002, TransAlta Utilities received the arbitrators' decision with respect to the force majeure dispute concerning the Wabamum Unit 4 outage. (The decision went into arbitration in July 2001). The arbitrators ruled that TransAlta should have returned the unit to service more quickly and, as a result, had to compensate the PPA holder approximately $30 million
- Another important risk relates to the generator's obligation to meet specified availability commitments. Generators are required to make a payment to the PPA holder if actual availability is below the specified availability of the respective unit. However, if generators exceed these thresholds, they are entitled to an incentive payment

Outlook for the Alberta Market

- Over the longer term, electricity prices in Alberta are expected to rise, as
  - higher cost gas replaces coal as the dominant fuel source
  - the costs of operating existing coal generation facilities increases to conform with more stringent environmental standards (i.e., Kyoto)
- Demand is expected to continue to grow along with the province's economic growth, which remains relatively strong
- Limited transmission interconnections with the other jurisdictions means the province will have to rely on new generation within the province
- While new coal-based generation is currently relatively inexpensive, it faces significant environmental costs, especially with the ratification of the Kyoto Protocol
- Therefore, most new generation required to meet the demand will continue to be predominantly gas-based or renewable energy-based due to environmental concerns
  - Gas prices are expected to remain higher over the medium term based on the current demand/supply conditions, which will result in higher electricity prices
  - Renewable energy generation is even higher cost, which will also contribute to higher prices
- There is currently about 5,290 MW either under construction or proposed over the 2003 to 2006 period.
- While Alberta's peak demand increased significantly in 2002, its average demand remains at around 6,730 MW, significantly below the total installed current capacity of 10,900 MW
- It is highly likely that a significant proportion of the proposed generation will not be built over the next three years
- All of this new generation will likely result in over capacity in Alberta

SASKATCHEWAN

Characteristics of the Saskatchewan Market

- In 2002, the peak electricity demand in Saskatchewan was approximately 2,822 MW, and total installed capacity is currently 3,468 MW
- Electricity sales in Saskatchewan average around 17 billion kWh annually (16.7 billion kWh for 2002)
- Total capacity by fuel source is as follows:

Fuel Source	Percentage	Capacity
Hydro	24.6%	853 MW
Coal	47.7%	1,653 MW
Natural Gas	27.7%	962 MW
Total		**3,468 MW**

Note: includes the Queen Elizabeth Power station (150 MW), which was re-powered in June 1, 2002, and Cory Cogeneration (260 MW), commissioned in December 2002.

- The province's current transmission interconnection capacity is limited at only 17% of provincial generating capacity, and consists of:
  - 300 MW with Manitoba Hydro;
  - 150 MW with Alberta;
  - 150 MW with US Basin Electric
- Peak energy demand exceeded installed capacity in three of the last five years, resulting in the reliance on imported power to meet the peak energy needs of the province
- However, with new capacity installed in 2002, there should be sufficient capacity within the province to meet peak energy demand over the medium term
- Saskatchewan Power Corporation, a Crown corporation, owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity in Saskatchewan
- SaskPower owns all of the transmission in the province and all of the distribution, with the exception of the municipalities of Saskatoon and Swift Current
- SaskPower wholly owns 3,030 MW of generating capacity in the province, is a 50% partner in the 228 MW Cory Cogeneration facility, and has a 25-year power purchase arrangement for the power from the 210 MW Meridian plant (owned by TransAlta Corporation and Husky Oil Limited)

Regulation in Saskatchewan

SaskPower is governed by the *Power Corporation Act* and is subject to the provisions of *The Crown Corporations Act, 1993*. The current regulatory model allows SaskPower to request rate adjustments with review by an independent rate review panel. The review process typically takes only 90 days, before a decision is handed down. The current Board-approved target rate of return on equity for SaskPower is 10%. A system-average rate increase of 2.0% was implemented on April 1, 2001 (the first since a residential rate increase in 1996). This was followed by another system average rate increase of 4.5%, which took effect on January 1, 2002.

SaskPower recently separated its regulated and non-regulated business units in order to facilitate the rate review process. Future rate applications will be made to provide a return on equity for the regulated operations only, ensuring there is no cross-subsidization of SaskPower's non-regulated business ventures.

While there are currently no further plans for market restructuring in Saskatchewan, SaskPower posted an Open

Access Transmission Tariff (OATT) that became effective on January 1, 2002. An OATT is an open offer of transmission service. This has opened the provincial transmission system to wholesale energy suppliers and users. This change also ensures SaskPower's access to the transmission systems of other electrical utilities, thus enhancing the corporation's trading and export opportunities. For a fee, eligible users are able to access SaskPower's transmission system to transport electricity to SaskPower's two wholesale customers, the municipal utilities in Saskatoon and Swift Current, or wheel it across the province for export to other jurisdictions. Independent power producers within Saskatchewan also have the ability to transport electricity to SaskPower's wholesale customers and to transport electricity out of the province. While the OATT allows the municipalities of Saskatoon and Swift Current to procure power from other jurisdictions, several factors make it uneconomical for these municipalities to do so, making it unlikely that SaskPower will lose these two customers.

Outlook for the Saskatchewan Market

- Beyond the OATT, it is unlikely that further market restructuring will occur in the province
- Given the costs of expanding inter-tie capacity, it is unlikely that the province's limited interconnections will be increased, which constrains SaskPower's ability to import electricity to address power needs
- However, with new generation built over the last couple of years and minimal load growth expected, there should be sufficient capacity within the province to meet energy demands over the medium term. Annual growth is estimated at under 1%
- Future additions to generation capacity will likely be financed by public/private joint ventures, as evidenced by the newly commissioned Cory Cogeneration project, which was a joint venture between SaskPower and ATCO Power Ltd. and the 25-year power purchase agreement from the Meridian cogeneration facility
- With its large coal-fired generation base, SaskPower is one of the largest emitters of CO_2 in the country
- With the ratification of the Kyoto protocol, the costs associated with cleaning up these coal-fired facilities could be substantial

MANITOBA

Characteristics of the Manitoba Market

- In F2002, the peak electricity demand in Manitoba was 3,760 MW, and total installed capacity was 5,203 MW
- Electricity sales in Manitoba in F2002 were 29.2 billion kWh, and have grown at a rate of 1.3% annually over the last five years
- The majority of Manitoba's generating capacity is hydro-based, which has a low load factor (in the 50% to 60% range):

Fuel Source	Percentage	Capacity
Hydro	95.1%	4,960 MW
Natural Gas	4.7%	233 MW
Oil	0.2%	10 MW
Total		**5,203 MW**

Note: All but 18 MW is owned by Manitoba Hydro.

- Manitoba's current export interconnection capacity is equivalent to about 56% of installed capacity, and consists of:
  - 450 MW to Saskatchewan
  - 263 MW to Ontario
  - 2,050 MW to the U.S. Midwest Independent System Operator (MISO)
- The Manitoba Hydro-Electric Board is a wholly owned Crown corporation of the Province of Manitoba
- Manitoba Hydro is a fully integrated utility that generates, transmits and distributes electricity throughout the Province of Manitoba
- With its purchase of Winnipeg Hydro in September 2002, Manitoba Hydro now owns all of the transmission and distribution assets in the province, and all but 18 MW (a sawmill company) of the generating capacity
- Manitoba Hydro is also the province's major distributor of natural gas through wholly owned Centra Gas Manitoba
- Low-cost, hydro-based generating capacity accounts for over 95% of installed capacity and results in one of the lowest variable cost structures in Canada (about 1.3¢ per kWh), surpassed only by Churchill Falls in Labrador
- Geographically, three diverse drainage basins reduce fluctuations in water flows and water levels caused by weather patterns in a specific region
- However, earnings at Manitoba Hydro are sensitive to hydrological conditions, as most of the generation capacity is hydro-based
- With extensive interconnection, low-cost, hydro-based generating facilities as well as substantial excess capacity, Manitoba Hydro is in an excellent position to export power into higher-priced jurisdictions
- Manitoba Hydro currently has long-term export contracts committing 1,410 MW of capacity in the summer months and 860 MW in the winter
- In late 2002, Manitoba Hydro signed a ten-year power supply contract with NSP Minnesota (a subsidiary of Xcel Energy Inc.), which will replace its existing export contract that expires in 2005

- Prior to open access in 1996, all exported power was sold at the border only to directly interconnected neighbouring utilities, which in turn delivered the power to their customers or re-sold it at a profit to other utilities
- Due to open access and the coordination agreement with MISO, Manitoba Hydro is now positioned to sell to more distant companies
- Retail customers in Manitoba currently enjoy electricity rates that are among the lowest in North America, due to Manitoba Hydro's low-cost hydro-based generating capacity and profitable exports
- Domestic electricity rates for large industrial customers have been voluntarily frozen since 1992 and since 1997 for residential customers, and will not likely be increased in the near term (especially with an upcoming election)

Regulation in Manitoba

The Manitoba Public Utilities Board ("PUB") regulates electricity rates in Manitoba. Proposed rate changes are submitted to the PUB by Manitoba Hydro. Traditionally, rates are reviewed annually and changes, if any, are effective the first of April. Domestic rates for large industrial customers have been voluntarily frozen since 1992 and since 1997 for residential customers, and will not be increased in F2003. In November 2001, the provincial government legislated equal northern, rural and urban electricity rates throughout the province, providing an significant subsidy to the low-population density regions in the north.

Prices for electricity exported or imported are determined by negotiated contracts. Export permits must be approved by the National Energy Board ("NEB").

In 1997, the Manitoba Legislature enacted significant amendments to the *Manitoba Hydro Act*. While Manitoba Hydro and Winnipeg Hydro (now a part of Manitoba Hydro) remain the sole retail electricity suppliers in Manitoba, other utilities may access the transmission system to reach other customers in neighbouring provinces and states. The amended Act explicitly allows Manitoba Hydro to build new generating capacity for export sales, to offer new energy-related services, to enter into strategic alliances and joint ventures, and to create subsidiaries.

Manitoba Hydro has restructured its operations into one Corporate unit and three operating units: (1) Power Supply, (2) Transmission and Distribution; and (3) Customer Service and Marketing. The structure mirrors those of other utilities who are adhering to Federal Energy Regulatory Commission directives in the United States.

Outlook for the Manitoba Market

- There are presently no plans to move to full retail competition in the province, as it is believed that Manitoba prices would likely increase from their current levels, which are the lowest in North America
- Based on forecasts of the wholesale trading price in the MISO region, Manitoba customers would likely pay 30% more if domestic electricity rates were market-based
- Manitoba Hydro recently completed the conversion of its Selkirk thermal generating station from coal to natural gas, along with environmental upgrades
- Key projects currently underway by Manitoba Hydro to expand generating capacity include:
  - Two new natural gas-fired turbines at the Brandon Generating Station (260 MW) in F2003, which will assist in meeting demand during periods of poor hydrological conditions
  - Construction of a 260 kV transmission line to North Dakota will increase export capacity (F2003)
- Other capacity expansion projects currently under consideration in northern Manitoba include:
  - Wuskwatim generating station on the Burntwood River (205 MW), estimated at $811 million including transmission, in-service date of 2009
  - Gull generating station (600 MW), in-service date of 2010
  - Notigi generating station (100 MW), in-service date of 2014
- Future generation projects in Manitoba will be expensive to develop given the remoteness of the project sites and the distances which transmission must extend to get the power to the regions requiring the supply

ONTARIO

Characteristics of the Ontario Market

- On August 1, 2002, Ontario hit a record high peak demand of 25,496 MW, roughly 4% higher than the previous high, which was reached in August 2001
- Electricity sales in Ontario in 2002 are estimated at 151,000 billion kWh, with a projected load growth of 1% annually over the medium term
- Total capacity by fuel source is as follows:

Fuel Source	Percentage	Capacity
Nuclear	31.7%	8,728 MW
Hydro	27.3%	7,522 MW
Coal	27.4%	7,553 MW
Oil/natural gas	13.3%	3,662 MW
Other	0.3%	77 MW
Total		**27,542 MW**

Note: This table does not include laid-up capacity consisting of four nuclear units at Bruce A and four nuclear units at Pickering A, totalling 5,136 MW.

- The major electricity generators in Ontario are:
  - Ontario Power Generation Inc. (wholly owned by the provincial government) with 22,169 MW (plus an additional 2,060 MW at Pickering A currently non-operational)
  - Bruce Power LLP with 3,160 MW of nuclear capacity leased from OPG (plus an additional 3,076 MW at Bruce A currently non-operational).
  - Other participants include Great Lakes Power Inc. with about 935 MW, and several other independent power producers such as Algonquin Power, Northland Power, TransAlta, and others
- Hydro One (wholly owned by the provincial government) owns substantially all of the transmission assets in Ontario
- Distribution assets are broadly held by Hydro One and 95 local distribution companies (LDCs)
- Of the 95 LDCs in Ontario, the 17 largest LDCs account for approximately 60% of total electricity throughputs and serve roughly one-third of the customers in the province

- Ontario also has over 5,500 MW of interconnection capacity with Michigan, New York, Minnesota, Manitoba and Québec (see table)

	Limit on Exports (MW)	Limit on Imports (MW)	NERC Regional Council
Michigan	Summer: 2,100 Winter: 2,200	Summer: 1,700 Winter: 1,700	ECAR
New York (Niagara Falls)	Summer: 1,800 Winter: 2,000	Summer: 1,300 Winter: 1,500	NPCC
New York (eastern Ontario)	400	400	NPCC
Québec	Summer: 835 Winter: 870	Summer: 1,450 Winter: 1,469	NPCC
Minnesota	140	90	MAPP
Manitoba	275	324	MAPP
Total Ontario Interconnection Capacity	Summer: 5,550 Winter: 5,885	Summer: 5,264 Winter: 5,483	

*Source: Independent Electricity Market Operator, December 23, 2002
NERC = North American Electricity Reliability Council
Note: the reliability councils are responsible for the security of supply of electricity within the council. Ontario boarders with the following reliability councils:
ECAR = East Central Area Reliability Coordination Agreement
NPP = Northeast Power Coordinating Council
MAPP = Mid-Continent Area Power Pool

Market Restructuring in Ontario

Energy Competition Act, 1998

- In October 1998, the Ontario government passed the *Energy Competition Act, 1998* ("Act") to deregulate and enable full competition in the electricity market in Ontario
- Under the industry restructuring, which became effective April 1, 1999, five separate entities were created from the former Ontario Hydro:
  - Ontario Power Generation Inc. owns and operates the generating assets
  - Hydro One Inc. owns and operates the transmission and distribution assets
  - Ontario Electricity Financial Corporation ("OEFC") is responsible for managing and retiring the outstanding debt and certain other liabilities of the former Ontario Hydro
  - Independent Electricity Market Operator ("IMO") is a non-profit corporation that performs the central market operating functions
  - Electrical Safety Authority ("ESA") is a non-profit corporation responsible for electric installation inspections

Key components of the Act for each of wholesale pricing, generation, transmission, distribution and retail are discussed below:

<u>Wholesale pricing:</u>

- There are two main components that make up the cost of electricity:
  - The wholesale price of the electricity (also known as the energy or commodity cost)
  - Various other costs such as transmission fees, debt retirement costs, and local distribution charges

- In Ontario's wholesale electricity market, which the IMO oversees, energy prices are determined by collecting offers from suppliers and bids from purchasers to determine the on-the-spot market price for electricity that reflects demand across the province
- Energy prices can change from hour to hour, day to night, and from season to season in response to changing levels in the demand, as well as changes in the availability of the supply of electricity
- The IMO monitors, evaluates, and analyzes the effectiveness of the market rules and underlying structure, as well as the conduct of market participants, to ensure the efficiency and competitiveness of the wholesale electricity market

<u>Generation:</u>
- The Act requires that OPG decontrol (i.e., relinquish effective control through sale or lease) a portion of its generating assets:
  - 4,000 MW of primarily fossil-based capacity within 42 months of open access
  - Reduce its capacity to no more than 35% of the province's available supply (measured in MW) within ten years of market opening
- OPG has made the following divestitures in order to meet decontrol targets:
  - In 2001, OPG leased its Bruce nuclear generation facility, to Bruce Power through a long-term agreement
  - In May 2002, OPG sold four hydroelectric stations on the Mississagi River (488 MW) to Great Lakes Power
- To date, OPG has been unsuccessful in finding a buyer for the four coal plants that it had identified for divestiture fossil: (1) Lakeview (1,100 MW), (2) Lennox (2,100 MW), (3) Thunder Bay (300 MW) and (4) Atikokan (200 MW)
- Under the market power mitigation agreement, OPG is directed to rebate annually to customers/retailers, through the IMO, the difference between the weighted average hourly spot price and 3.8¢/kWh times 90% of OPG's estimated sales into the Ontario market (excluding imports) for that year
- All other generators bid their electricity into the open wholesale market and receive the market clearing price

<u>Transmission:</u>
- With the restructuring of Ontario Hydro, Hydro One became the largest owner of transmission assets in the province
- The OEB became the regulator for Hydro One's transmission and distribution subsidiary (Hydro One Networks)
- Hydro One was granted an approved ROE of 9.88% (in 1999) on its transmission assets, and was to move to performance-based regulation beginning in 2004

<u>Distribution:</u>
- Municipal Electric Utilities (MEUs) were previously regulated by the former Ontario Hydro
- The Act gave the Ontario Energy Board ("OEB") the authority to set the rates for electricity distribution utilities in Ontario
- Under industry restructuring which became effective April 1, 1999, MEUs were directed to incorporate as local distribution companies, and to separate ("unbundle") their distribution component ("wires") from non-wires operations such as energy marketing (sale of the commodity), generation and energy services
- Regulation for distribution companies under the Act consisted of a rate of return on equity and performance-based regulation
  - LDCs were granted an ROE of 9.88% based on a deemed capital structure ranging from 50/50 debt/equity for smaller LDCs to 65/35 for larger LDCs such as Toronto Hydro Corporation
  - Performance-based regulation consisted of annual adjustments to rates incorporating a (1) performance improvement factor and (2) an inflation adjustment
  - In addition, rates could be adjusted by a z-factor to account for any unusual items
- With the majority of the LDCs retained by municipalities, the deemed capital structure was achieved through the LDC issuing a promissory note to the municipality
- The increase in distribution rates to achieve 9.88% was implemented equally (one-third each year) over a three-year period. The third phase was to be implemented in March 2003, but was eliminated following the government's announcement of Bill 210 (see below)
- Many LDCs were retained by the municipalities in which they operate (i.e., the municipality as the sole shareholder), 87 were bought by Hydro One (mostly in rural areas), and others were sold to and/or amalgamated with larger LDCs
- Currently, 95 LDCs exist in Ontario
- Currently, there is little incentive for further acquisitions given that a 33% transfer tax must be paid on the proceeds from a sale

<u>Retail:</u>
- Upon market opening, electricity customers in Ontario were given the choice to:
  - Sign a long-term electricity supply contract with an independent electricity retailer or
  - To remain on a standard supply service (SSS), with electricity supply provided by the LDC and the wholesale cost of electricity passed through to customers
- SSS customers were billed the average monthly wholesale cost of electricity

Sale of Hydro One

- The provincial government had planned to privatize Hydro One with the sale of its ownership in the company through an initial public offering in the spring of 2002
- However, on April 19, 2002, following a legal challenge on the sale by two labour unions, an Ontario court ruled that the provincial government did not have the authority to sell Hydro One
- In the fall of 2002, the provincial government amended legislation to allow it to sell Hydro One and announced that it would sell a 49% share of the Company
- On January 20, 2003, the provincial government announced it would retain 100% ownership of Hydro One

Market Opening - May 1, 2002

- The wholesale and retail electricity market in Ontario opened on May 1, 2002
- Since the electricity market opened to competition, the arithmetic average hourly price has ranged between 0.8¢/kWh and $1.03/kWh, with the peak occurring on September 3, 2002
- The average monthly wholesale price for electricity is shown in the table below:

Month	Avg. Monthly Price (¢/per kWh)	Volume Sold (billion kWh)	Peak Hourly Demand (MW)
May	2.92	11,875	20,068
June	3.51	12,193	23,578
July	5.82	14,050	25,226
August	6.42	13,749	25,414
September	7.52	12,593	25,062
October	4.80	12,423	21,219
November	4.94	12,710	21,948
December	5.63	14,023	23.475
Arithmetic Average	5.20	12,952	–
Weighted Average	5.59	–	–

- Two factors contributed to significantly high electricity prices in August and September 2002:
  - Unusually high temperatures
  - Lack of sufficient generation capacity
- As such, a significant amount of higher-priced electricity was imported from other jurisdictions

Bill 210 – November 11, 2002

- On November 11, 2002, following two months of unexpectedly high wholesale electricity prices, the Ontario government announced a halt to the restructuring process
- Bill 210 outlined the following, effective from December 1, 2002 until at least 2006:
  - Freeze the retail commodity price of electricity at 4.3¢/kWh
  - Cap distribution rates at current levels
  - Cap transmission rates at current levels
  - Allow the wholesale electricity market to continue to operate according to the forces of supply and demand
  - Provide tax incentives to encourage new generation cleaner renewable energy sources
- On December 9, 2002, Bill 210 became law
- **Bill 210 will have the greatest negative effect on retail companies and distribution companies, while the effect on transmission and generation will be minimal**

The effect of Bill 210 on each of wholesale pricing, generation, transmission, distribution and retail are discussed below:

Wholesale market:

- The direct effect of Bill 210 on the wholesale market will be minimal, since the wholesale market price of electricity will continue to float freely with the forces of supply and demand dictating the price

Generation:

- The direct effect of Bill 210 on electricity generators is expected to be minimal, since generators will continue to receive the wholesale market-clearing price for the electricity it sells into the spot market
- However, the impact on OPG will be greater than for investor-owned generation
- The Ontario government (as OPG's sole shareholder) will use OPG as a the primary source of funding the difference between the retail rate of 4.3¢/kWh and the spot price:
  - OPG must still rebate the difference between the spot price and 3.8¢/kWh (as outlined under the market power mitigation agreement)
- DBRS believes it is unlikely that decontrol of OPG's assets, to reduce the company's market share (as outlined under the original Act), will get very far under the new legislation, due to the following:
  - The government has given direction to OPG to engage in the development of generation projects, such as an expansion at Niagara Falls
  - Current revenue stream from OPG and rebates under the market power mitigation agreement will go a long way towards funding the 4.3¢/kWh retail rate freeze
  - Much of OPG's existing coal-fired generation capacity requires expensive upgrades to meet environmental compliance, which creates a disincentive to potential buyers

Transmission:

- The effect of Bill 210 on transmission is minimal since, transmission companies (mainly Hydro One) have been allowed to earn a 9.88% ROE since 1999
  - However, the actual ROE will depend on Hydro One's ability to manage its costs, since it will not be able to increase rates to cover any increases in operating costs

- Hydro One will continue to operate with a deemed common equity at 36% and deemed preferred equity at 4%
- Until at least 2006, there will be few instances whereby Hydro One could submit a rate application to the OEB for an increase in rates
- The only instance is if Hydro One receives the Minister of Energy's approval to submit the application. There are certain conditions that must be met for the Minister of Energy to provide approval, with the two most important being:
  - If Hydro One has incurred extraordinary costs
  - If the Minister of Energy is of the opinion that other circumstances justify giving approval
- The effect on other smaller transmission companies is minimal since they are already entitled to the full 9.88% ROE. However, managing costs will become extremely important since an increase in operating costs cannot be passed along to customers
- For transmission, the OEB is expected to play a limited rate-making role until at least 2006

<u>Distribution:</u>

- The capping of distribution rates, as outlined in Bill 210, will have a negative impact on electricity distributors:
  - LDCs will not be entitled to collect the final installment of rate increases necessary to achieve a 9.88% ROE (leaving an ROE of only 6.6%), thus pressuring earnings
  - Transition and other one-time costs will likely not be recoverable until at least 2006
- In addition, individual municipal councils must elect to allow their LDC to remain a commercial (for-profit) entity by March 9, 2003 or they will automatically become not-for-profit entities (with rates reduced to earn a zero percent ROE)
  - An LDC's credit quality would be at risk if the LDC's shareholder (typically a municipality) decides to return the utility back to being a not-for-profit entity. Under this scenario, coverage ratios would drop significantly, thereby reducing protection for creditors
- The provincial government has eased the impact on LDCs somewhat since first announcing Bill 210:
  - Certain variance accounts are now recoverable through credits from the IMO
  - The total amount of prudential requirements to the IMO (for the purchase of wholesale electricity) has been reduced, thus improving LDCs' financial flexibility
  - Certain transmission charges (uplift and low-voltage) have been frozen to LDCs. Thus, LDCs will no longer be at risk for any variances due to these charges
- Key issues that have not been resolved include:
  - The amount of payments in lieu of taxes (PILS) included in future rates
  - The mechanism and timeline as to how and when items defined as "regulatory assets" will be recovered through rates
- For Hydro One's distribution operations:
  - For distribution that it had historically owned – the ROE is implicitly 9.88%, although the last one-third of the rate increase necessary to recover the October 1, 2001 increase in the wholesale cost of power will not be implemented
  - For the acquired MEUs – the ROE will be 3.30% given that at the time of Bill 201, Hydro One had only implemented the first one-third of the rate increase required to achieve the 9.88% ROE
- For distributors, the OEB is expected to play a limited rate-making role until at least 2006

<u>Retail:</u>

- With the introduction of Bill 210, there is essentially no market left for electricity retailers in Ontario since there is no incentive for customers to sign a fixed-term contract with rates frozen until 2006
- However, existing contracts are not at risk, since the government will pay out retailers for any fixed-term contracts signed before December 1, 2002
- Opportunities for retailers are limited to:
  - Larger customers who are not eligible for the government guaranteed rate freeze
  - Offering bundled services (i.e., gas and electricity), which together may provide added value to customers

<u>Other impacts of Bill 210</u>

- With a fixed retail electricity price that is relatively low, there is little incentive for consumers to conserve electricity, despite the government's efforts to encourage energy conservation
- Investor confidence has eroded since the announcement of Bill 210, discouraging investment in new generation projects
- Certain costs associated with facilitating Bill 210 may add to the stranded debt, which eventually will have to be passed along to electricity customers in the future

Outlook for the Ontario Market

- For the time being, market restructuring, as outlined in the *Energy Competition Act, 1998*, remains in limbo

New Generation/Transmission Capacity:

- Additions to capacity over the near term include:
  - Return to service of Pickering A unit 4 (515MW), expected in the summer of 2003
  - Return to service of two units at Bruce A (1,538 MW), expected in the summer of 2003
  - Sarnia Regional Cogeneration plant (650 MW) in 2003
  - Brighton Beach Cogeneration (580 MW) in 2004
  - With Bill 210, the government has identified expansion projects for OPG and offered incentives for electricity from renewable sources. However, nothing material has been announced

- Two future interconnection expansion projects are:
  - Interconnection with Hydro Quebec (1,250 MW), although capacity is not expected to be available before 2007
  - The Lake Erie Link (975 MW high voltage DC) to the PJM system. This has been deferred with recent government intervention

Wholesale Pricing:

- Under Bill 210, the wholesale market for electricity will continue to function, with generators receiving the hourly market clearing price for the electricity they sell into the spot market
- The IMO is projecting an average annual increase in electricity consumption of 0.9% to 1.1% over the next ten years
- With approximately 3,500 MW laid-up nuclear capacity and new cogeneration projects is expected during the 2003 to 2005 period, there should be sufficient new supply to meet about a decade's, worth of demand growth
- Under current forecasts of increased demand and with new capacity coming on line in 2003, average electricity prices are expected to stabilize in the 4.0¢ to 4.5¢/kWh range over the medium term
- Further support for this price expectation:
  - Even with current capacity constraints, the weighted average hourly electricity price since May 1, 2002 is only 5.59¢/kWh
  - This average price should trend downwards by May 1, 2003 (one full year with market-based wholesale prices) as the spring shoulder season is factored into pricing

- Factors that will continue to contribute to price volatility include:
  - Seasonality: extreme temperature differentials in the local environment (cold weather increases demand from electric heating and warm weather increases demand from air conditioning)
  - Daily demand fluctuations: peak demand tends to occur in the early evening and base demand occurs at night
  - More expensive gas-fired generation is utilized during peak (daily and seasonal) periods
  - Generators are taken out of service for maintenance, causing fluctuations in supply
  - Capacity constraints over the near term, until new generation comes online (expected in mid-2003)
  - Prices in ECAR and New York power pools, given the extensive interconnection capacity with Ontario and the export and import of power

- Key factors that may cause the future price to trend upwards over the medium to longer term include:
  - New capacity, beyond the refurbishment of laid-up nuclear generation, will likely be from natural gas, which costs about 6½¢/kWh (based on current gas and transportation costs)
  - Environmental costs associated with the Kyoto Protocol may make electricity generated from existing coal-fired plants more expensive
  - Depreciation of the Canadian dollar will continue to make imported power from the U.S. more expensive

QUÉBEC

Characteristics of the Québec Market

- In 2002, the Québec market had peak demand of about 32,000 MW and total capacity of about 41,000 MW, including Churchill Falls
- Electricity demand in Québec is currently just over 152 billion kWh/year

- Total capacity is composed of:
  - 31,174 MW from Hydro-Québec;
  - 5,428 MW available from Churchill Falls (Hydro-Québec has the rights to most of this power to 2040); and
  - 4,217 MW from IPPs
- Total capacity by fuel source is as follows:

Fuel Source	Percentage	Capacity
Hydro + wind	84.1%	34,336 MW
Oil & diesel	3.9%	1,591 MW
Gas	<1%	30 MW
Nuclear	1.6%	675 MW
Other renewables (IPPs)	10.3%	4,187 MW
Total		**40,820 MW**

- There is 2,282 MW of hydro capacity currently under construction by Hydro-Québec
- Québec is a net exporter of energy and has significant interconnection capacity, which allows it to maximize the market's export potential
- Québec currently has 6,825 MW of interconnection export capacity, roughly 16.7% of generation capacity, made up of:
  - 1,195 MW with Ontario
  - 1,200 MW with New Brunswick
  - 2,305 MW with New England
  - 2,125 MW into New York state
- Hydro-Québec and Hydro One have jointly agreed to postpone the construction of an additional 1,250 MW interconnection between Québec and Ontario
  - This capacity is not expected to be available before 2007
- Hydro-Québec is a provincial Crown corporation, and is the dominant electricity company in Québec.
  - It is a fully integrated utility that generates, transmits, and distributes electricity to over 3.5 million customers in Québec, equivalent to about 97% of Québec's electricity market
- The other electricity players in Québec are composed of:
  - IPPs on the generation side, and
  - nine municipal distributors and one regional cooperative on the distribution side

Regulation in Québec

Hydro-Québec's transmission and distribution operations are regulated by the Province of Québec's Régie de l'énergie.

In 2000, the provincial government amended the *Act respecting the Régie de l'énergie,* which included: (1) The clarification of the deregulation of generation (it removed electricity generation from the Régie's jurisdiction). While generation remains unregulated, Hydro-Québec retains sole responsibility for developing hydro sites with a capacity of over 50 MW; and (2) The establishment of a heritage electricity pool for Québec consumers. For Hydro-Québec, it means that the generator must supply the distributor with a maximum of 165 billion kWh/year for Québec customers at a set price of 2.79¢/KWh. The Régie has essentially granted a monopoly to Hydro-Québec as domestic sales are currently just over 152 billion kWh/year. The Act also introduced competition to the wholesale market for all needs in excess of the heritage pool. The wholesale market had already been open to competition since May 1, 1997. However, none of the distributors has exercised the option to date given the low cost of power offered by Hydro-Québec. Québec currently has one of the lowest cost sources of electricity in North America.

Hydro-Québec's transmission and distribution operations are regulated by the Province of Québec's Régie de l'énergie. There are no plans currently to introduce retail competition.

In 2001, the transmission division filed its first rate case with the Régie. In early May 2002, Hydro-Québec received the Régie's decision. The Régie approved a deemed capital structure of 70/30 debt/equity, and an ROE of 366 bps above long-term Government of Canada bonds. The newly approved rates will be applied retroactively to January 1, 2001 and are expected to be revised by the Régie for 2003.

The distribution division submitted its first rate case to the Régie in July 2002. The rate case submitted is to determine the cost of service for the purpose of establishing rates for the 2004-2005 fiscal year. Domestic retail rates have been frozen since 1998 and will remain frozen until April 2004.

Outlook for the Québec Market

- Electricity demand in Québec is currently just over 152 billion kWh/year and provincial demand is expected to grow at about 1.5% per year
- The generation division of Hydro-Québec must supply the distribution division of Hydro-Québec with a maximum of 165 billion kWh/year for Québec customers at a set price of 2.79¢/KWh
- The generation division of Hydro-Québec has 2,282 MW of hydro capacity currently under construction, which should provide sufficient capacity to meet its requirement of supplying the distributor with 165 billion kWh/year of electricity
- Demand is expected to exceed 165 billion kWh/year starting in 2006-2007
- In 2001, the distribution division of Hydro-Québec submitted its electricity supply plan for the next 10 years to the Régie de l'énergie to deal with the projected demand beyond the 165 billion kWh/year.
- In February 2002, the distribution division of Hydro-Québec issued a call for tenders for the purchase of 1,200 MW of firm power to meet domestic needs starting in March 2007. In October 2002, the distribution division of Hydro-Québec announced the selected bidders to provide electricity starting in 2007

for a term of 15 to 20 years. At the same time, it was announced that there would be additional calls for tender for green power in early 2003

- The need for new generation beyond 2006-2007 has already resulted in increased private sector generation projects in Québec and should increase competition
- Hydro-Québec, however, continues to have the sole responsibility for developing hydro sites with a capacity of over 50 MW. There are number of large projects, mainly hydro, currently in the negotiation or planning phase, which could add significant generation capacity. These include:
  - Agreements signed with the Crees for the development of two hydroelectric projects in the James Bay region: the Eastmain-1 and Eastmain-1-A generating station projects, along with the diversion of the Rupert River. Construction of Eastmain-1 began in 2002 as well as the draft-design studies and authorization phase for the Eastmain-1-A and Rupert diversion projects. The estimated cost of the two projects is $3.8 billion, with total installed capacity at about 1,250 MW
  - Draft design studies underway for the construction of a 450-MW hydroelectric generating station on the Péribonka River
  - Draft design studies underway for the construction of an 800-MW combined cycle gas-fired plan next to the Beauharnois canal
  - Draft design studies underway for a 220-MW hydroelectric generating station on the Romaine River
- While negotiations between the provincial governments (those of Québec and Newfoundland & Labrador) have stalled once again, the development of Lower Churchill remains a potentially large source of electricity available to Québec as well
- Given the dominance of hydro-based generation in Québec, combined with the fact that most of the large projects currently under construction and under development are also hydro-based, the cost of power in Québec is expected to remain low, although the capital cost of developing large scale hydro generation projects is high
- Hydro-Québec's low cost of power combined with its water storage capabilities and its excellent interconnection capacity, places Hydro-Québec in an excellent position to become a significant and highly profitable energy trader, especially in the U.S.

NEW BRUNSWICK

Characteristics of the New Brunswick Market

- Peak electricity demand in New Brunswick averages near 2,800 MW, and total installed capacity is 3,986 MW
- Annual electricity sales in New Brunswick have varied between 19 billion kWh to 20 billion kWh over the last four years
- Total installed capacity by fuel source is as follows:

Fuel Source	Percentage	Capacity
Oil	27.8%	1,108 MW
Hydro	23.1%	919 MW
Nuclear	15.9%	635 MW
Coal	12.9%	515 MW
Natural Gas	8.2%	327 MW
Orimulsion	7.5%	300 MW
Other	4.6%	182 MW
Total		**3,986 MW**

Note: NB Power owns 3,769 MW of generating capacity.

- New Brunswick currently has 2,570 MW of interconnection capacity, equivalent to about 64% of installed capacity, and consists of:
  - 1,060 MW with Hydro-Québec
  - 500 MW with Nova Scotia Power Corporation
  - 200 MW with Maritime Electric in Prince Edward Island
  - 810 MW with New England Utilities
- New Brunswick Power Corporation, a Crown corporation, generates, transmits, and distributes electricity in the Province of New Brunswick
- NB Power is the principal generator of electricity in the province, and owns and operates approximately 95% of total generating capacity in New Brunswick
- The remainder of generation capacity is largely made up of co-generation in the pulp and paper industry, along with some small hydro
- NB Power distributes electricity to approximately 88% of customers in New Brunswick, with the remainder supplied by three existing municipal utilities (Saint John, Edmundston, and Perth-Andover)
- NB Power is well positioned geographically to wheel and/or export electricity to the U.S. northeast. However, current high oil prices make the Utility's power less competitive in the U.S. northeast
- The availability of the 635 MW Point Lepreau nuclear station is important to New Brunswick as it provides around 25% of NB Power's electricity supply. During periods of plant unavailability, more expensive power purchases are required to replace the electricity that would otherwise be provided by Point Lepreau
- NB Power's 635 MW Point Lepreau nuclear generating station continues to represent a challenge for NB Power
  - The station continues to experience a wide range of problems relating to pressure tubes and feeder pipes
  - There were five unscheduled outages during F2002, totalling 44 days, resulting in a capacity factor of 82.5% (however, much better than the 65.1% in F2001)

- A major refurbishment, at an estimated cost of about $850 million, will be required by F2006 or F2007 (for an 18-month duration)
- Without the refurbishment, closure of Point Lepreau would be required some time between 2007 and 2010, and new base load capacity would be required to replace the power lost from Point Lepreau

- NB Power will likely proceed with the Point Lepreau refurbishment with third-party equity participation. In fact, DBRS expects that it is unlikely that the provincial government would support NB Power in undertaking Point Lepreau without an external partner
- Total divestiture of Point Lepreau is also possible

Regulation in New Brunswick

NB Power is regulated by the Board of Commissioners of Public Utilities of the Province of New Brunswick and is governed by applicable guidelines as set out in the provincial government's Energy Policy. As these directives also incorporate an economic agenda (i.e., maintaining low rates to sustain provincial economic growth), NB Power's allowable earnings are restricted to 1.25 times interest coverage. This is well below what regulated utilities in the private sector are allowed to earn.

Restructuring of New Brunswick Power Corporation

- The provincial government recently decided to maintain NB Power as a Crown corporation and undertake a major restructuring of the Utility including a debt for equity swap (i.e., recapitalization) and allowing equity positions or partnerships in future business development projects
- This will allow NB Power to transfer some of the risk/cost associated with future projects to other parties and reduce balance sheet pressure for NB Power
- By April 1, 2003, NB Power will be restructured into NB Power Holding with the following four wholly owned business units:
  - Generation company
  - Nuclear company
  - Transmission company
  - Distribution/customer service company
- Each subsidiary will be required to:
  - Earn a positive rate of return on equity
  - Pay a cash dividend to the Province
  - Pay appropriate income and capital taxes
  - Borrow funds without a provincial government guarantee
- The capital structure of each entity would likely be set at a proportion that more closely resembles an investor-owned utility. The Province would make a debt for equity swap and, in return, would require dividend payments and/or payments in lieu of taxes
- This type of corporate structure facilitates divestiture of individual components of the business, should the government decide to do so in the future

Restructuring of the New Brunswick Electricity Market

- The provincial government released its White Paper – *New Brunswick Energy Policy 2000-2010* in January 2001. The policy outlines a managed transition to the restructuring of the electricity sector:
  - The transition will begin by permitting existing distribution utilities (wholesale customers) and large industrial retail customers connected directly to the transmission system to procure power in the competitive market, as of April 1, 2003
  - Customers not eligible or not choosing to obtain electricity supply in this manner will be entitled to standard offer service, similar to the current service provided by the existing utility
  - Periodic review of market developments will determine how quickly the province moves towards full retail competition
- In June 2002, the multi-stakeholder Market Design Committee released its final report containing recommendations on a framework and implementation of a restructured New Brunswick electricity market, as outlined in the energy policy. Legislation allowing for reorganization of NB Power and restructuring of the electricity market is anticipated to be in place by January 2003. Key characteristics of restructuring are:
  - New Brunswick will institute a bilateral contract market in which wholesale customers and large industrial customers will be able to contract with alternative suppliers for electrical energy needs
  - Any power generator or supplier will be permitted to sell by contract to eligible customers inside and outside the province
  - Open and non-discriminatory access to the transmission system for eligible buyers and sellers will be provided, which will help to satisfy requirements of the Federal Energy Regulatory Commission
  - Once NB Power is reorganized on April 1, 2003, the system operator, responsible for operating and administering the market and the electricity supply system, will be totally independent of the owners of generation
  - Initially, the standard offer service will be supplied by a "heritage pool" of electricity available from the existing generation assets in the province
  - As generation assets retire or additional supply is required, the standard offer service supplier will go to the market, via a Request for Proposals, for additional supply

- A bilateral contract market will increase the responsibilities of the provincial regulator to include oversight of the system operator and monitoring for the abuse of market power

Outlook for the New Brunswick Electricity Market

- Three key projects that NB Power has identified include:
  - Point Lepreau Nuclear station refurbishment, at \$850 million (18-month outage beginning in 2006 or 2007)
  - Coleson Cove generating station conversion to be fuelled by orimulsion, at \$747 million (planned for completion in November 2004)
  - A second 345 kV transmission interconnection to New England, at \$45 million (planned for 2005 completion)
- The Utility is expected to proceed with these projects with third-party equity participation, which is facilitated under the new legislation
- Given its heavy reliance on thermal-based generation (60% of installed capacity), NB Power must contend with future environmental concerns, such as the Kyoto Protocol
  - CO_2 emissions remain the key concern, as SO_2 will be sharply reduced over the next few years with certain plant conversion projects.
- Conversion of oil-based plants to lower cost fuels or dual energy facilities should help to materially reduce costs and emissions in the future. Emissions of SO_2 will be sharply reduced over the next few years with:
  - The conversion of Courtenay Bay from a 100 MW oil-fired plant into a 280-MW combined cycle natural gas facility (given an expected increase in natural gas prices, Courtenay Bay will likely be operated as a peaking facility)
  - The closure of the 57 MW Grand Lake coal-based plant by 2004
  - The conversion of Coleson Cove to orimulsion with emission reducing scrubbers

NOVA SCOTIA

Characteristics of the Nova Scotia Market

- Peak demand in Nova Scotia is approximately 1,800 MW, and total installed capacity is 2,267 MW
- Electricity sales in Nova Scotia for 2002 are estimated to be approximately 12 billion kWh
- Load growth in Nova Scotia has averaged 3.6% annually over the last five years due to strong economic growth in the province over the period
- Total installed capacity by fuel source is as follows:

Fuel Source	Percentage	Capacity
Coal	56.1%	1,272 MW
Hydro	16.9%	383 MW
Dual Fuel	11.0%	250 MW
Natural Gas	7.9%	180 MW
Oil	4.4%	100 MW
Alternative	3.6%	82 MW
Total		**2,267 MW**

Note: All but 84 MW is owned and operated by Nova Scotia Power.

- Currently, 500 MW of interconnection exists with New Brunswick, equivalent to approximately 23% of installed capacity
- Nova Scotia Power Inc. is a regulated electric utility that provides more than 95% of electric generation, transmission, and distribution to more than 440,000 customers across Nova Scotia
- Nova Scotia Power was privatized in the early 1990s, and remains an example of one of Canada's most successful privatizations of a Crown-owned utility
- Nova Scotia Power is a wholly owned subsidiary of Emera Inc., a diversified energy and services company
- Nova Scotia Power is one of the higher-cost generators in Canada, even compared to other thermal-based operators
- The relatively high electricity rates make Nova Scotia an attractive market for potential competitors. In spite of this, the Utility's limited interconnection capacity and the province's isolated geographic position provide an effective barrier against new market entrants
- Neighbouring utilities in the U.S. northeast have significantly higher electricity rates and, therefore, are less likely to export into Nova Scotia Power's market. Hydro-Québec, the only potential Canadian competitor, has significantly lower electricity rates, but is more likely to export to U.S. markets where it can earn higher revenues
- While coal-based generation comprises approximately 56% of generation capacity, over 75% of volume of electricity sold in Nova Scotia (in kWh) is from coal-based generation
- Tightening of emission standards on coal-based generation (to reduce NO_X, CO_2 and SO_2) could lead to potentially expensive capital investment over the longer term

Regulation in Nova Scotia

- Currently, there are no plans for deregulation or market restructuring in Nova Scotia
- Nova Scotia Power is regulated by the Nova Scotia Utility and Review Board ("UARB") and operates under a cost of service/rate of return methodology
- In October 2002, NSPI received the UARB's ruling on its 2002 rate application (its first rate application since 1996), providing NSPI with a rate increase of 3.3% effective November 1, 2002
- Key components in the rate decision are as follows:
  - An allowed return on equity of 10.15% (+/- 25 basis points) based on a 35% deemed equity
  - The ability to increase common equity up to 40%. However, deemed equity remains at 35% for rate-making purposes (thus, for rate making purposes, there is no advantage to the utility increasing equity to 40%)
  - The UARB outlined several controls and measures that must for the separation of duties between NSPI and its parent, Emera Inc.
- Nova Scotia Power withdrew its 2003 rate application, but is expected to file its 2004 rate application in mid-2003
- The 2004 rate application will likely include a request for a tax pass-through to customers, given that Nova Scotia Power will begin paying corporate taxes in 2003
- Regulatory lag in Nova Scotia is material, especially since rate decisions cannot be implemented retroactively. For example, the UARB took 11 months to review the Company's 2002 regulatory filing, which had a negative impact on Nova Scotia Power's earnings and cash flow in 2002 as the regulator's decision was not finalized until October 2002

Outlook for the Nova Scotia Market

- Electricity prices increased in November 2002 for the first time since 1996
- With a mature market and initiatives in place to increase plant utilization at Nova Scotia Power, there will be no need for large investments in utility assets
- Electricity rates are expected to increase again in 2004 if Nova Scotia Power is permitted to pass through its increased tax burden to its customers
- The Utility's generating capacity (over 75% of energy produced) is 58% coal-based. The Utility must manage potential environmental risks associated with changes in emission standards, such as the installation of expensive scrubbers on existing coal-based facilities
- With the ratification of the Kyoto Protocol, the costs associated with cleaning up coal-fired facilities in the province could be substantial
- However, using cleaner burning coal from international suppliers will help reduce emissions in the future
- Imported coal now makes up about 90% of the Company's coal supply, with the closing of the Cape Breton Development Company's coal mines in Nova Scotia

NEWFOUNDLAND AND LABRADOR

Characteristics of the Newfoundland and Labrador Market

- Peak demand in Newfoundland and Labrador is approximately 1,870 MW (in 2001), while total installed available capacity is about 2,435 MW (excludes electricity generated at Churchill Falls for delivery to Hydro-Québec and production by Menihek Power in Northern Labrador supplying Schefferville Québec)
  - Of this available capacity, about 1,839 MW is located on the Island portion of the province, while 596 MW of capacity is available for Labrador loads
  - Of the total net installed capacity, some 8 MW on the Island and 22 MW in Labrador serve various isolated rural communities are not interconnected to the primary power grids
- Electricity demand in Newfoundland and Labrador was just under 11 billion kWh in 2001
- Electricity requirements in the province can be somewhat variable from one year to the next depending on the operating conditions pertaining to the province's industrial customers, and also weather conditions owing to the large market share for electric space heating
  - Over the past five years, provincial loads have been stable overall owing to various economic and weather factors. On a weather normal basis, typical load growth projections are about 1% annually
- Total installed capacity by fuel source is as follows:

Fuel Source	Percentage	Capacity
Hydro	70%	1,704 MW
Thermal	30%	731 MW
Total		**2,435 MW**

- The Island of Newfoundland and the Labrador mainland have no transmission interconnection to other jurisdictions. Labrador has 5,500 MW of high voltage transmission interconnection capacity with Hydro-Québec related to deliveries from the Churchill Falls facility
- Newfoundland and Labrador Hydro ("NLH"), a Crown corporation of the Province of Newfoundland and Labrador, is the dominant generation and transmission electric power company in the province. In addition, NLH directly serves residential and commercial distribution customers in more rural service areas of the Island and throughout all of Labrador
- NLH has a net installed capacity of 1,554 MW (887 MW hydro and 667 MW thermal). In addition to this, NLH has title to 300 MW of recall power from the Churchill Falls facility in Labrador and long-term supply contracts on the Island presently amounting to 19 MW of independent power production
- NLH sells approximately 50% of its available supply to an investor-owned electricity distributor, Newfoundland Power Inc., which is wholly owned by Fortis Inc. NLH's remaining power deliveries are directed to the province's larger industrial companies, short-term exports of unused recall in Labrador to Hydro-Québec, and its own distribution customers across the province
- Newfoundland Power operates an integrated distribution system throughout most of the Island of Newfoundland, along with some related transmission and generation facilities
  - Though operating only on the Island portion of the province, Newfoundland Power serves approximately 85% of all residential and commercial distribution electricity customers in the province and has a local peak demand of 1,100 to 1,200 MW
  - With an installed capacity of 148 MW, Newfoundland Power normally generates under 10% of its total electricity requirements, and purchases the balance of its needs from NLH
- The remainder of the installed generation capacity on the Island of Newfoundland (about 200 MW) is hydro-based generation, which are industry-owned IPPs
- The hydroelectric plant located at Churchill Falls has an installed capacity of 5,428 MW, 90% of which is dedicated to Hydro-Québec under a long-term contract. The remaining 10% represents the available resource for the Labrador interconnected system. The Churchill Falls (Labrador) Corporation Limited operates this facility and is 65.8%-owned by Newfoundland and Labrador Hydro with the remaining ownership held by Hydro-Québec. Typical annual net electricity production from this facility is in the order of 33 billion kWh

Regulation in Newfoundland and Labrador

Newfoundland and Labrador Hydro is regulated by the Board of Commissioners of Public Utilities. In 1996, the province enacted legislation that changes the way the Utility is to be regulated to a rate of return basis. In May 2001, the Utility filed its first general rate application since 1991 and its first full rate base application. The Board released its decisions with respect to the application on June 7, 2002. The following includes the key decisions rendered by the Board that will have an impact on the Utility's finances: (1) the annual re-basing of the price of Bunker C fuel used for rate stabilization purposes to an average fuel price based on monthly forecast fuel prices (the base price had been set at $12.50/bbl since 1992). This was a significant problem since Newfoundland and Labrador Hydro had to finance the difference between the $12.50/bbl and the higher market price. (2) The removal of the existing $50 million cap on Newfoundland Power's portion of the Rate Stabilization Plan. (3) The deferral of additional recovery of the existing RSP balances (balance as at August 31, 2002) until 2003 to be recovered over a five-year period. (4) An ROE of 3% and a regulated debt/equity ratio of 83/17 for 2002. (5) Approval of a target short-term debt/equity ratio of 80/20 (beyond 2002). (6) Approval to move to full cost recovery for federal and provincial government departments in rural areas. The PUB did not accept the Utility's request to move to a ROE and capital structure over the longer term that is more comparable to those of investor-owned utilities.

The Utility plans to file another rate application in 2003 to adjust 2004 rates to recover the costs associated with the new power coming on line from Granite Canal, as well as the cost of power purchases from non-utility generators.

Outlook for the Newfoundland and Labrador Market

- The Government of Newfoundland and Labrador established an electricity policy review process in 1998. In March 2002, the government completed a comprehensive review of the electricity industry in the province. Subsequent to the completion of the review, the government initiated a public consultation process about issues and options for the future
- The consultation process has ended and the government is currently reviewing the results of the consultant's report
- The key generation project currently underway by Newfoundland and Labrador Hydro is the Granite Canal project, a new $135 million, 40-MW generating facility
  - It is expected to be operational by mid-2003
- The other capacity expansion projects currently under development reside with two industrial generators – Abitibi-Price and Corner Brook Pulp & Paper
  - These companies own and operate their own hydro generation plants and sell the excess power to Newfoundland and Labrador Hydro

- The expansion projects under development by these two companies include:
  - Addition of a turbine at the Grand Falls plant;
  - Refurbishment of the Bishop's Falls plant; and
  - A new cogeneration plant in Corner Brook
- Beyond these expansion projects, the only other project currently under discussion between the Québec and Newfoundland and Labrador governments is the development of the Lower Churchill, which will be an expensive project to undertake

PRINCE EDWARD ISLAND

Characteristics of the Prince Edward Island Market

- Peak electricity demand in Prince Edward Island is around 195 MW
- Maritime Electric, wholly owned by Fortis Inc., is the principle electric utility on PEI, serving approximately 67,000 customers, roughly 95% of electricity consumers in the province
- The majority of the remainder of electricity customers are served by the City of Summerside Electric Utility, operators of the only municipal electric utility on the Island
- Maritime Electric owns and operates a fully integrated system providing for the transmission and distribution of electricity on PEI, and a minimal amount of generation
- The system is interconnected to the mainland power grid via two submarine cables under Northumberland Strait
- Most of the energy supplied to customers is purchased from New Brunswick Power
- Maritime Electric maintains 104 MW of diesel-fired generating capacity on the Island, which is kept in standby mode and is put into operation when energy supply from off-island sources is interrupted. This is very expensive power
- In 2001, Maritime Electric in conjunction with the provincial government commissioned a 5 MW wind-generation facility on the western tip of the Island

Regulation in Prince Edward Island

- Currently, there are no plans for deregulation or market restructuring in Prince Edward Island
- Under the terms of the *Maritime Electric Company Limited Regulation Act (1994)*, electricity rates on PEI can be no greater than 110% of New Brunswick electricity rates for equivalent service in New Brunswick.
- The Act also prescribes minimum reliability standards and requires the company to maintain at least 40% of its capital structure in the form of common equity
- Beginning April 1, 2002, legislative changes to the Act allow Maritime Electric to:
  - Recover from/return to customers 90% of all energy related costs above/below $0.05/kWh
  - Recover from/return to customers a cost of capital adjustment based on an 11% target return on average common equity

Appendix A – Methodology for Rating Electric Utilities

In assigning a rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. Key considerations will vary, but in very general terms, common themes for most ratings include the mixture of quantitative and qualitative factors discussed below, which are not in order of importance. Taken together, these factors provide a relatively complete range of rating considerations for the electric utility sector although this is not meant to imply that this list is exhaustive. While some considerations would normally be more important, the order of importance can and does change with time and by company. In certain cases, a major strength can compensate for a weakness that would be more critical for a peer company. Conversely, there are cases where one weakness is so critical that it overrides the fact that the company may be strong in most other areas. In summary, the overall objective is to arrive at an evaluation of the company's business risk profile and how it balances with the company's financial risk profile.

QUANTITATIVE CONSIDERATIONS

The Financial Model

General quantitative factors (subject to adjustments due to qualitative considerations) used by DBRS for "A"/BBB ratings are as follows:

	Regulated	Mixed	Unregulated
% debt in capital structure	60%-70%	50%-60%	50%
Fixed-charges coverage	1.5	1.5-2.0	2.0
Cash flow/debt	0.10	0.10-0.15	0.15-0.20

- Amount of financial risk that can be assumed depends on whether the company is regulated, mixed, or unregulated
- Regulated operations are typically more stable, and are subject to lower levels of competition
- Unregulated activities typically have greater business risk, so must be balanced with lower financial risk
- "Mixed" companies' capacity to assume financial risk depends on the mix of regulated and non-regulated operations
- Fixed-charges coverage and cash flow/debt ratios are highly sensitive to the amount of debt in the capital structure
- The above ratios do not translate directly into a given rating, since the subjective factors must also be considered

Regulatory Status

The amount of debt that a given company can carry for an "A"/BBB rating varies with the sectors in which it operates. A regulated entity, with the greater certainty and stability, can generally carry more debt than an organization operating in the riskier unregulated area, other things being equal. The "regulated" category includes generation, transmission, and distribution; "mixed" includes companies that have both regulated and unregulated components; and "unregulated" includes both pure merchant power (usually generation and retail) and traditional utilities operating in unregulated environments.

% Debt / Capital

The percentage of debt is defined as short-term and long-term debt, divided by short-term and long-term debt, plus equity. When leases are significant, the capitalized value of the lease is added to both the numerator and denominator.

Regulated entities, which generally operate in transmission and distribution, can usually carry 60% to 70% debt. However, this declines to 50% to 60%, as activity becomes more unregulated and subject to greater instability, uncertainty, and business risk. Historically, utilities were able to carry more debt than industrial companies because of the stability and certainty inherent to a regulated environment. This changed when deregulation and the break-up of the traditional functions of generation, distribution, and transmission occurred. New standards for the debt levels that can be carried by utilities are needed, and DBRS has isolated some general standards, as shown above.

Debt levels establish the strength of related ratios as ratios work in concert across various ratio thresholds. For example, cash flow/debt with 60% debt levels is often near 0.10. However, if debt levels fall to 50%, the cash flow/debt ratio often improves sharply to the 0.15 to 0.20 range. Debt levels below 50% usually result in a cash flow/debt ratio of 0.15 to 0.20 or better. Thus, once the proportion of debt is established, most other ratios move in tandem. The basic theory behind the standards is simple. The riskier, completely unregulated area, including merchant power, can carry less debt (50%), versus higher debt (60% to 70%) for a less risky, completely regulated generation transmission distribution company, other things being equal. A mixed company can carry 50% to 60% debt, depending on the degree of deregulation. However, as discussed later, this scenario is oversimplified, and there are many other qualitative factors that establish the final rating, and often supersede rigid quantitative standards. Therefore, the standards outlined above have to be adjusted to include many subjective factors.

Fixed-Charges Coverage

Fixed-charges coverage is defined as earnings before interest and taxes, divided by interest, plus tax-adjusted preferred share dividends. If leases are large, one-third of the minimum lease payment is added to the numerator and denominator of this ratio. Regulated entities standards for an “A”/BBB rating are 1.5 times, while unregulated entities should have a higher safety margin, with coverage above 2 times. The mixed group (deregulation/regulation) is in between, at 1.5 to 2.0 times coverage. The ratio is measured over a period of time, so a temporary fluctuation outside these standards may not affect the rating.

Cash Flow / Debt

Cash flow is defined as income before extraordinary income, plus depreciation, plus normal deferred taxes, divided by total debt. This ratio is consistent with the other ratios shown. With debt levels above 60%, it is difficult to bring this ratio above 0.10 times for many utilities. As debt levels approach 50%, this ratio’s strength usually improves to the 0.15 to 0.20 range. The riskier unregulated area should have a ratio of 0.20 times, while stable regulated sectors can be closer to 0.10 times for “A”/BBB ratings, provided the qualitative factors previously mentioned do not influence results.

Aside from the key financial considerations discussed above, the following quantitative factors are an important element in the rating assessment. The following are in no particular order of importance:

(1) What is the proportion of unregulated and regulated revenue and income for a mixed utility?

(2) What is the fuel mix? Coal, hydro, and nuclear are superior to more costly natural gas and oil, which are usually used for peaking purposes or as emergency support if base load generators fail.

(3) What is the forward price curve for electricity in the company’s region?

(4) What is the general long-term outlook for electricity in the marketplace, and how have electricity prices behaved since inception of deregulation?

(5) What is the economic strength of the franchise area, and is it growing or shrinking?

(6) What is the size of the utility? Smaller utilities are less diversified and more affected if one generator goes down, versus large utilities.

(7) What is the nature of demand between peak and trough, and how seasonal is demand?

(8) Are rates between residential, commercial, and industrial equitable, and is there potential new rate balancing needed?

(9) What is the average cost for electricity, versus the average costs in the country. Regionally?

(10) What is the proportion of coal generation, and do environmental issues exist? What is the degree to which future capital expenditure will have to be raised for environmental reasons?

(11) What is the long-term projected growth in electricity demand in the regional market?

(12) What percentage of total income is derived from the riskier trading area and how aggressive is the utility?

(13) What is the sole mix of the demand for electricity between residential, commercial, and industrial? Is there one large dominant customer?

(14) How dense is the concentration of customers, and are there vast areas with relatively few customers?

(15) How sensitive to temperature (residential customers) and economic factors (industrial customers) is the franchise area?

(16) How much reliance is there on outside power, versus self-generated power?

QUALITATIVE FACTORS

There are a substantial number of qualitative factors that go into the final rating that can override the actual strength of the financial ratios. For example:

(1) Review of risk management and the overall control structure, including policies, procedures, strategies, and execution (see discussion topics in the attached report).

(2) What is the risk appetite in the trading/marketing area?

(3) What is the hedging policy, and are the fuel source and final electricity prices received hedged? To what degree? For how long, and with what counterparties?

(4) What is the quality of counterparty risk for fuel purchased and electricity sold. Policies with respect to counterparty risk?

(5) What are the conditions and general characteristics of the transmission grid and distribution network?

(6) What investments does the company have internationally? Which are subject to political, currency, regulatory, and counterparty risk?

(7) What is the regulatory structure? Favourable or unfavourable? Does regulation operate on future looking performance or is there regulatory lag?

(8) Does performance-based regulation exist and, if so, what are the characteristics? Favourable or unfavourable?

(9) What transmission constraints exist, and can these constraints limit new supply?

(10) What is the availability of natural gas into the marketplace, and at what prices can greenfield power be produced in the marketplace?

(11) What is the nature and characteristic of competition in the marketplace? Is the power generated in the franchise area, or does it come from outside the market area?

(12) Does the firm exercise “market power” in its region? Or near “market power”?

(13) Do power purchase agreements exist? Terms?

Other qualitative considerations not specific to the energy sector include the following:

(1) Strength and depth of senior management and the board of directors? Experience? Do they have a track record of under or overachieving?

(2) Strategic and tactical planning. Aggressive or conservative? Is it well thought through?

(3) Financial flexibility, liquidity, access to alternate sources of capital.

(4) Capital expenditure levels? Acquisition and expansion plans?

(5) Funding structure. Dependence on short-term debt? Debt maturity schedule? Are there rating triggers?

(6) Legal issues and escalating legal costs.

(7) Accounting quality (see discussion on FASB 133 in the attached report).

(8) Debt issue specific - terms and conditions.

(9) Bank line agreements - terms and conditions.

(10) Event risk considerations.

Appendix B - Discussion of the Various Electricity Segments

(1) **UNREGULATED**
(2) **REGULATED**
(3) **MIXED**
(4) **THE RETAIL SECTOR**

(1) THE UNREGULATED ENVIRONMENT

Strengths:
- Deregulation raises growth prospects, as traditional utilities expand into faster growing activities
- Consolidation of generation raises size, critical mass, and efficiency for a utility
- Larger size improves diversification, geographically, and by fuel type
- Technological improvements in generation improve efficiency for new generators and a deregulated environment encourages
- Coal and nuclear are two lower-cost and desirable fuels, accounting for over 70% of U.S. generation. In a competitive deregulated environment, these fuels will be favoured for existing plants
- Stranded cost recovery has been assured in most jurisdictions, assuming the stranded costs result from deregulation

Challenges:
- New generation capacity typically uses gas, which is the most expensive fuel, and usually the "marginal" fuel for pricing
- Transmission grid limitations restrict smooth electricity flow, and create many submarkets for electricity
- Regulation in merchant power still persists where company has excess market clout
- Excess additions of generation capacity create over-supply
- Balance sheets of many companies weakened by aggressive expansion in the 1998 – 2001 period
- Expansion in Asian and Latin American markets presents substantial political, currency, regulatory, and counterparty risk
- Loss of stable transmission and distribution activities for "mixed" companies reduces control in this area
- Use of marked-to-market and marked-to-model accounting under FASB 133 increases earnings volatility and enables earnings management

Unregulated Generation Area (Merchant Energy) – The Nature of the Market

The deregulated area appealed to many utilities that were tired of lengthy rate application hearings, regulatory lag, and intervener conflicts. However, after the California and Enron experiences, as well as the transition through the "initial stages" of a deregulated environment, some of the utilities are longing for the "good old days." The simple fact is that deregulation means more competition and price instability. The "security" provided by a regulator is gone. In Europe, electricity prices in deregulated environments have fallen 30% to 50% in areas such as the U.K. and Germany. The more regulated areas such as France and Italy have experienced very minimal price decreases, as the traditional utilities maintain immense market clout, and competition is limited. In addition, the higher-risk, non-regulated area has the capacity to carry lower debt levels. In other words, the higher business risk must be balanced with lower financial risk.

Strengths and Challenges - Detailed

Strengths: (1) Separation of electricity into its four main components (generation, transmission, distribution, and retail) has given the electric companies scope for much greater growth and profitability. Deregulated electric generation does not have the degree of earnings restrictions that exist in the regulated transmission and distribution area.
(2) Consolidation and size have given the larger companies critical mass and efficiency. The large U.S. electric industry was extremely fragmented, relative to Europe and Canada. Mergers created larger and more specialized companies (i.e., power generators) which are often more efficient.
(3) Larger size is also improving diversification by geographical area and fuel type, although the merchant energy producers have reduced influence in the regulated and stable transmission and distribution sector.
(4) Technological improvements, especially those related to natural gas generation, are reducing the cost of generation. For example, more recent gas turbines can produce electricity using 7,000 Btus per kWh, versus over 10,000 Btus for many of the coal-based generators.
(5) Coal and nuclear generation account for over 70% of U.S. generation. Both fuels have been highly stable in price, and lock in stable cost structures for the utility.
(6) Stranded costs resulting from deregulation are usually due to two main factors: (a) recovery of costs related to under-depreciation of nuclear plants; and (b) third-party power contracts above market prices. As the transition from regulated to deregulated prices occurs, most utilities are able to recover these capitalized "stranded" costs. Recovery is usually over ten years, and is assessed as a surcharge added to the cost of transmission.

Challenges: (1) Deregulation has resulted in construction of too many new plants in some areas. This increases the electrical supply, and has been instrumental in reducing the price of electricity in certain regional markets. Electricity is a pure commodity, and sensitive to any excess supply, just like oil. A small excess can result in depressing prices, particularly those associated with peak power requirements.
(2) Lack of transmission interconnection, and the difficulty in building new transmission networks restricts the ability to transmit power. It can also result in stranded electricity, where the lack of transmission facilities forces a utility to "dump" power at prices as low as its variable costs.
(3) Regulation has not been completely eliminated in generation. For example, FERC and state regulators are still influencing prices if a given company is deemed to have too much market power, as in California.
(4) New capital expenditure in generation has been predominantly using a natural gas base. Since gas is the most expensive fuel today, these new plants will be the first to be shut down when demand falls (i.e., in a recession). Thus, many of the new gas-based plants will be peaking plants rather than generating base load requirements, operating only a few hundred hours a year with the hope that peaking prices will be high enough to earn favourable returns and justify their investment. If regulators cap rates, the peaking plants are the first to experience problems.
(5) Balance sheets have been weakened through aggressive expansion in new generation capacity. Through the use of limited partnerships, the companies have been able to finance some of these projects "off balance sheet." This off-balance sheet financing is justified as long as the company does not support the trust in some fashion, and the company can, in effect, walk away from a given project without supplying additional support. Leasing and securitization are two other off-balance sheet items that must be monitored. (Enron supported most of its off balance sheet debt.)
(6) Some companies have made investments in third world countries in Asia and Latin America. This presents these companies with unique political, currency, regulatory, and counter-party risk, as proven by recent examples in India and Brazil. U.S. companies have also not fared well in developed countries such as the U.K. and Australia, where regulatory restrictions have severely cut returns and often created large losses for the utilities.
(7) The electrical companies are subject to price risk, and the recent decline in electric prices in the U.S. severely restricts profitability on plants without long-term power contracts.
(8) The merchant power generators generally have reduced control in the stable transmission and distribution area.
(9) The quality of accounting of merchant power generators now allows companies greater scope to manage earnings, due to the illiquid nature of forward price curves. In particular, FASB 133 (marked-to-market/marked-to-model accounting) gives companies substantial scope in managing income through the valuation of these contracts.

(2) Regulated Activities: Generation, Transmission/Distribution

Strengths:

- Regulation generally assures stability, and limited competition usually exists
- Volume variance and fuel price flow-through protection often exists
- Performance-based regulation shares future efficiencies between customers and the generator
- Most stranded cost flow recovery is allowed, in most jurisdictions, except for stranded costs not common in a regulated environment

Challenges:

- Risk of unfavourable regulation as the regulatory framework and market structure is changed by both federal and state authorities
- Transmission control shifting to independent system operators
- Lack of new transmission line construction
- Lack of "synchronization" of the power grid
- Technological improvements in gas generation may "strand" some transmission and distribution grids
- Electric growth is stable and mature, at only 1% to 2% per franchise area under normal conditions

Summary

While regulation usually assures stability of income, the rates of return earned are usually "normal," and not as high as in the unregulated area, and there are a number of regulatory issues that are in conflict. Growth is mature and slow, and transmission control is gradually shifting to regional transmission grids which will be separated from the main utility. Being in a regulated area is not always attractive, if regulation is not favourable.

Regulated Companies: Generation, Transmission/Distribution

Strengths: (1) The area is regulated with "protection," assuring stability of income.
(2) Protection, depending on jurisdiction includes: (a) volume variance protection due to temperatures, with reserve accounts to smooth out fluctuations; and (b) fuel price protection, with pass-throughs of fuel price variances. Fuel price fluctuations may be recovered over long time periods in the rates.
(3) Performance-based regulation shares the benefits of efficiency between customers and the Company. Although agreements often exist for five-year periods, extensions have been occurring after the five-year period without "rebasing" old efficiencies, which then remain shared into the future.
(4) Interest costs are generally flowed through to the customer and generally do not represent a problem during periods of high interest rates.
(5) Line losses of electricity in transmission and distribution are passed on to the customer in the form of higher rates.

Challenges: (1) Transmission control is gradually changing. The mixed electric companies are being encouraged to transfer control of their transmission grids to regional transmission companies, which cut across various states, and allow open access to all generators of power. The transmission grid is usually controlled by an independent system operator. This increases the level of competition in the electric industry, and allows for transmission of power over a much larger economic area.
(2) Environmental factors and a "not in my back yard" mentality prevent the extension of the North American transmission grid. This prevents build-up of the rate base, and restricts growth of transmission company profitability.
(3) Lack of synchronization of power in the four major power sectors in North America prevents free flow of electricity. The four major regions are the eastern U.S., western U.S., Texas, and Québec. It is difficult to get power between these four North American regions. The flow of transmission grids in North America is also North/south. East/west interconnections in North America are weak.
(4) Falling interest rates are also resulting in lower allowed return on equity.
(5) Regulation can be in conflict, as inter-state electricity flow is governed by FERC regulation, and retail distribution is regulated by the states. This leads to regulatory lag, turf wars between regulators, costly and lengthy rate hearings, and frustration on the part of the utilities.
(6) Electricity growth is mature, and seldom exceeds 1% to 2% per year in most markets, unless the franchise area has unusually high growth. With limited rate base growth and falling interest rates, the growth rate of transmission/distribution companies is not high, unless the franchise area is booming. Acquisitions are usually needed to show any substantial growth.
(7) Technological improvements in gas-based generation may "strand" some of the transmission capacity which exist.
(8) There can be unfavourable regulation, with regulatory lag and unfavourable decisions.

(3) Mixed: Regulation and Deregulation

Strengths:
- Provides some stability, some growth
- Capacity exists for greater-than-regulated returns, especially with performance-based regulation

Challenges:
- Generation in new jurisdictions raises business risk
- Subject to greater competition in unregulated area
- "Mixed" often means that the area has not yet deregulated, but will eventually

Summary

The mixed area of deregulation/regulation is often an area that has not yet deregulated, but could eventually be deregulated. However, the utility holding company may have merchant generation plants in another market area. Business risk and competition are greater in the mixed environment than for the purely regulated utility, but so is the potential profitability of the unregulated activities.

With the recent difficulties in the industry, several firms have recently re-integrated their merchant power operations alongside their regulated utility operations.

The experience with Enron and California has slowed the degree of deregulation, but eventually most of North America will, in our opinion, be deregulated. As the Regional Transmission Organizations are created, generators of power will have scope to ship electricity to more customers over greater distances with more competition. This may increase competition, as the monopoly enjoyed by any one utility is diminished.

Strengths and Challenges – Detailed

Strengths:
(1) This area combines all the strengths of regulated and deregulated operations. It offers a balance of growth and some stability. The deregulated area is usually generation, while transmission and distribution usually remain regulated.

Challenges:
(1) The challenges include all the factors discussed under the sections of regulated and deregulated entities.

(2) The business risk involved with companies in the deregulated area is greater than with the regulated sector.

(3) The deregulated area is subjected to greater competition than regulated, and greater price fluctuations.

(4) The mixed area is often a jurisdiction that has not yet deregulated, and will eventually do so. Utility holding companies may purchase merchant power plants in a totally independent market area.

(4) THE RETAIL SECTOR

In this section, we briefly discuss the Retail Sector, which has unique characteristics within the Unregulated segment.

Definition

Retail is defined as the final sale of the commodity, electricity. Electricity is purchased wholesale and sold to retail customers, with the company initiating the sale:

(1) Not having generation facilities;
(2) Not having transmission facilities; and
(3) Not having distribution facilities.

The company makes money by (1) breaking bulk (buying high volume for fixed prices for several years, and reselling smaller volumes to customers) for shorter periods, (2) playing time spreads, by selling electricity under two- to three-year contracts, but buying it under much shorter-term contracts or vice versa, selling shorter and buying longer and (3) using financial derivatives to hedge its positions and trading the commodity.

Strengths:

- Area acts as another profit centre
- Superior software and administration skills needed
- Usually involves all energy products – gas, electricity

Challenges:

- Hedging policy is key
- Severe counterparty risk can result
- Large size needed to be competitive
- Severe energy price fluctuations raise problems
- Application of FASB 133, marked-to-market accounting extremely complex

Strengths and Challenges - Detailed

Strengths: (1) The area acts as another profit centre for the company, as it makes money off the raw commodity. Many utilities, especially in Canada, have chosen not to do this, and hedge their fuel/electricity positions instead.
(2) Most companies in this area have superior software technology to control hedging, and to bill clients. Receivable collection is key, and companies need excellent administration skills.
(3) Most companies in this area trade not only electricity, but gas as well. This gives them a second profit centre.

Challenges: (1) Hedging policy is key to the long-term profitability and stability of income. There is no such thing as a perfect hedge, so the Company has degrees of hedging risk.
(2) Significant counter-party risk exists with respect to (a) electricity and gas supply, and (b) customer contracts for electricity and natural gas.
(3) Large size is needed to (a) buy gas and electricity, (b) create the sophisticated software to administer and control, and (c) attain enough capital to have the clout to overcome price fluctuations, and to market the products properly.
(4) Severe energy price fluctuations cause problems with buyers and sellers. Liquidity in the certain forward markets can be extremely thin, which creates difficulties when hedging.
(5) Marked-to-market accounting is highly complex and creates volatility of earnings. In addition, it gives wide scope for manipulation and management of earnings.

Other Considerations

Debt Levels and Capitalization – Off-Balance Sheet Features

- To compensate for off-balance sheet features, significant adjustments, and changes have to be made to the financial statements of energy companies
- In some cases, goodwill is high, but its value is questionable. What is book equity net of goodwill?
- Off-balance sheet, non-recourse debt should be added to total debt, if these amounts are not already consolidated
- Off-balance sheet operating leases (synthetic leases) should be included with total debt
- Special purpose vehicle debt (often from securitizations), which is off-balance sheet should be added to total debt
- The DBRS adjusted debt in the capital structure ratio includes all these debt equivalent obligations
- For hybrid securities, the question remains: is it debt or is it equity?
- DBRS has a four-tier definition of whether a hybrid security is debt or equity:
  - Maturity – debt has a maturity date, equity is permanent
  - Subordination – debt is senior, equity is junior. What is the security's level of priority?
  - Legal Status – interest must be paid on debt, while "dividends" for equity can be deferred. Does the security allow payment deferrals, and under what conditions?
  - Intent – Is the intent of the company to keep the securities out forever, or to eventually redeem them?

Different instruments receive different degrees of equity treatment by DBRS (see DBRS report entitled Hybrid Securities)

Generation Mix

- Generation plant for power companies falls into three components – base load, intermediary (or seasonal), and peaking generation
  - Base load often consists of coal/nuclear base and it operates continuously
  - Intermediate (seasonal capacity) are plants usually operated in winter and summer to supply seasonal peaks
  - Peaking plants are used to meet peak demand, and are generally run for very limited amounts of time
- Peaking plants are usually the highest-cost units, and have flexibility to be shut down quickly when generation is not needed
- Peaking plants are also to support base load plants shutting unexpectedly
- Fuel source in peaking plants is usually gas
- Gas is now one of the most expensive fuels, second only to oil in cost
- Future gas prices will rise (in opinion of DBRS) so future gas-fuelled generation costs are expected to increase over time
- Almost all new generation capacity being developed is based on gas. This will ultimately lead to long-term increases in power prices
- Coal-based generation has been affected by environmental issues, and nuclear-based generation is out of favour
- As electricity demand grows, leaves only high-cost gas as an alternative for substantial growth in future generation capacity
- This means that as electricity demand grows, average prices per KWh will rise
- Canada gets over 50% of its electricity from hydropower, a very low-cost fuel
- Hydro used as base load (run of the river hydro) or for peaking where generators have storage capacity for the water
- Hydro-Québec good example of entity using hydro generation for peaking: it sells power during on peak times, and conserves water off peak – buying off peak power
- Hydro-Québec's hydropower base has storage for most of the 35,000 MW hydro generation it owns or controls, and is therefore one of best positioned electrics in North America for the arbitrage of peaking capacity
- However, Hydro-Québec requires better transmission interconnections to optimize its returns

STRATEGIES OF ENERGY COMPANIES

Is strategy high-risk, middle-risk, or low-risk?

(1) **Low-Risk Strategy**

- Power and fuel costs are locked in for the same term, and at prices that flow-through fuel costs
- Contracts can be long-term in nature; for instance, ten years or longer. The longer the contract, the more closely it parallels the life of the generator
- However, the longer the contract, the greater the potential counterparty risk
- Counterparties must be of good credit standing, generally BBB (low) or better
- Things can still go wrong, even if a generator is almost perfectly hedged
- Good example is TransAlta, which contractually sold power for the remaining lifetime of its Alberta generators
- The TransAlta power purchase agreement (PPA) allow for the recovery of costs (variable and fixed), as well as providing for a return on equity of 450 bps above ten-year Government of Canada bonds on a deemed equity component of 45%
- When the generator failed, TransAlta was deemed to be partially at fault, and had to absorb part of the losses
- TransAlta encountered a similar problem in Washington state with its coal-based generator
- TransAlta was forced to purchase wholesale power at prices that were far above those it was receiving from the PPAs in order to meet the PPAs contractual supply obligations

(2) **Middle-Risk Strategy**

- Power and fuel costs locked in for varying time periods and durations, and do not necessarily coincide
- Company engages in some “financial” trading, where it arbitrages markets and spot/futures to a limited degree
- Moderate proportions of power and fuels are sold to and purchased from spot markets
- Not all power or fuel supply contracts are hedged
- Trades with a few riskier counterparties with credit in the BB credit range are undertaken, although the majority of the trading book remains with higher-rated counterparties
- Company must maintain sufficient liquidity and collateral to trade with lower-rated counterparties, limiting such activity
- Most companies adopt this middle-risk strategy

(3) **High-Risk Strategy**

- Power sales are to spot markets, or are based on relatively short-term contracts
- Fuel supply not locked in via contract, or such contracts differ in duration and timing from power supply contracts
- High proportions of fuel mix are natural gas or oil, both highly volatile and expensive energy sources
- Amount of hedging limited – most sales are made to spot markets
- Aggressive “financial” trading arbitraging spot/futures, markets, times zones, and fuels
- Heavy emphasis on trading activities as a source of earnings
- Enron and Dynegy good examples of companies in this category
- Large trading floors and teams of traders employed to facilitate strategy
- Merchant energy company may have high proportion of “peaking” generators, (gas-fuelled) in generation mix
- Peaking generators “riskier,” as these are “swing” generators – generally economic to operate only when prices are high
- Some counterparties rated non-investment grade constitute meaningful amount of trades
- However, declining levels of available liquidity and collateral are making such high-risk strategies uneconomic

Appendix C – Comparison of Canadian and U.S. Energy Companies

THE U.S. ENERGY COMPANY BUBBLE – WHAT ARE THE CAUSES?

Factors Causing the Problems:

- Numerous mergers and acquisitions
- Aggressive generation expansion
- Virtually all recent expansion of generation is based on one fuel: high-cost natural gas
- Aggressive international expansion
- Exposure to the telecommunications industry
- Aggressive accounting and FASB 133
- Market and bank sensitivity to creditworthiness and liquidity problems
- Litigation risk, and increasing litigation related to California's energy pricing, "round-trip" trading, and so forth

Effects of Above Problems:

- Very high debt levels, and weak financial ratios
- Loss of credibility with investors and financial institutions
- Sharp cutbacks in trading
- Reductions in proposed new generating facilities, and "temporary" suspension of work on facilities already under construction
- Asset sales to raise cash, with some sales featuring distress pricing
- Near-bankruptcy for some
- Increasing scrutiny from various levels and areas of government (SEC, FERC, and so forth)
- Resources and energy devoted to managing litigation rather than the company

COMMENTS

Energy companies are defined to include pipelines, and Merchant Power entities. These companies have gone through substantial change over the past several years. The process started with the restructuring of electricity producers, which led to the separation of generation, transmission, and distribution. Rapid technological change and industry deregulation (restructuring) are the two key changes that cause crises in any industry at any time. As restructuring and deregulation occurs, companies take large risks that result in problems until the "learning curve" has been mastered and normal activities stabilize. This is exactly what happened in the energy area. The California crisis in energy came first, followed by the Enron crisis.

The main factor causing the crisis was aggressive expansion through (1) mergers; and (2) construction, both domestic and international, including (a) expansion in telecommunications, and (b) generation expansion, basically using one fuel: natural gas. Aggressive accounting, which in some cases bordered on fraud and included off-balance sheet financing, helped mask the true trends of cash flow and reported debt levels. The net results were higher debt levels, and ultimately a liquidity crisis when they lost access to the capital markets and bank debt. Credibility has been lost with banks and investors, and the non-investment grade ratings eliminate traders due to counterparty collateral and liquidity requirements.

Lack of access to the capital market means asset sales have to be initiated to raise cash, and several energy companies have been on the edge of bankruptcy if sufficient cash or credit could not be accessed. Lawsuits related to the California problems in 2000 and "round-trip" trading will linger, but eventually (approximately three to five years) with further cutbacks, asset sales, and mergers, normalcy will return.

BACKGROUND

Many of the major U.S. energy companies have varying degrees of liquidity problems, as companies encounter difficulty paying off debt obligations and renewing bank lines. Ratings have been reduced to non-investment grade status, and energy companies are selling assets at "fire sale" prices to raise cash. Major companies are fighting for survival in the U.S. (which is in direct contrast to the situation in Canada). The major reasons for this crisis in the U.S. and the likely outcome are as follows:

Factors Causing the Crisis with Energy Companies:

(1) Many Mergers and Acquisitions

- Energy companies bought existing operating power plants – usually outside their own franchise area
- In addition, actual acquisitions of energy companies were made
- Most acquisitions heavily debt financed
- Long approval periods for mergers (often two years) created uncertainty for major electricity companies
- State and federal approval system complex and tedious
- Companies directed too much effort at gaining approval for the mergers, and not enough on running the company
- Many acquisitions overpriced in a buoyant energy market
- Acquisitions created goodwill, which later would have to be written off, thus recognizing overpayment

(2) Aggressive Expansion of Generation Capacity

- Energy companies significantly expanded generation capacity – inside and outside their own franchise areas
- Very capital intensive, and added greatly to debt levels
- Not all expansion locked into long-term power contracts
- Sensitive and vulnerable to decline in case of economic slowdown or anything that would cause a drop in energy prices

(3) Percentage of Natural Gas-fired Generation Capacity Increases

- Nearly all new generation capacity fuelled with natural gas – coal and nuclear out of favour
- Natural gas and oil fuel the most expensive generation capacity today
- Result is that as electricity demand slows, natural gas units first ones to shut down
- Long-run outlook for gas indicates increasing natural gas price levels, which have been artificially low in the past
- Coal/uranium prices much more stable, making natural gas less cost competitive
- Result is that natural gas generation plants are being used primarily for peaking, where long-term contracts often do not provide price protection

(4) Aggressive International Expansion

- Many U.S. energy companies invested aggressively in Asia, Latin America, Eastern Europe, and Africa
- This led to very high currency, political, cost over-run, and regulatory risk for companies that jumped into markets they knew little about
- Aggressive tactics used by U.S. companies in the U.K. and Australia
- Some of the worst losses were incurred in the U.K., as regulation changed
- At one time, U.S. utilities owned 8 of the 12 regional electric units (electricity distribution) in the U.K.
- Poor regulatory decisions and increased taxes caused some massive investment write-downs for U.S. utilities in the U.K. and Australia
- Losses in developing countries such as India and Pakistan even more spectacular for U.S. companies
- Most Argentine and Brazilian energy projects also produced large losses

(5) Telecommunications Exposure

- Many energy companies have some exposure to the telecommunication entities – most of which were self created
- Enron and Williams Communications are the best known examples of electrics with telecommunications exposure, but many energy companies had some exposure to telecommunications
- These companies provided broadband services to business, using railway or pipeline right of ways
- Williams guaranteed $2.2 billion of debt of its telecommunications unit, which filed for bankruptcy, and Williams had to absorb the debt

(6) Aggressive Accounting

- Aggressive off-balance sheet debt was often not disclosed in any way
- Leases, non-recourse project debt, and special purpose vehicles or entities were created and used to get off-balance sheet treatment
- The debt of these entities was off-balance sheet, but rating trigger points and quasi-guarantees often resulted in effective parent support for the debt
- FASB 133 will continue to be a problem, because it gives too much scope for a company to manage earnings, with broad assumptions used to record and manipulate income
- Round-trip trading was used by several firms to artificially record higher trading volumes, as well as to create artificial prices, which were then used to raise quarterly reported income on a mark-to-market basis
- Such flexible accounting standards cost energy companies credibility with investors and banks
- Substantial off-balance sheet financing causes debt on the balance sheet to be understated, while excess goodwill due to the acquisition of over-priced assets results in the overstatement of equity
- Enron and other companies also used creative accounting when recognizing revenue, including aggressive recognition of future revenue and excess cost capitalization to the balance sheet, thereby inflating income

(7) Bank Sensitivity to Creditworthiness

- As loan losses mounted, especially in energy and telecommunications, banks became concerned about their own credit ratings
- Energy companies (including electrical and pipelines) and telecommunications companies are under the worst credit pressure and have become prime targets for cutbacks
- Situation with telcos and energy companies similar to 1992 cycle when real estate companies had trouble getting credit from banks
- Situation will prevail until present problems are cleared up – could be at least two years
- One result is that energy companies are selling assets at “fire sale” prices to raise cash
- For example, Dynegy sold Northern Natural Gas Pipelines to Warren Buffet for $928 million cash, versus its $1.5 billion purchase price in early 2002; this was a large loss in a short time for a company that needed liquidity to ensure long-term survival

(8) Litigation and Associated Risks

- Various lawsuits are under way, with many directly related to the collapse of energy traders such as Enron
- California best known: lawsuits have been initiated against various companies that are accused of manipulating energy prices
- Companies involved in round tripping or wash trading to inflate volume and income have also resulted in lawsuits
- Litigation will last for many years, and ultimately a costly settlement will likely result
- Meanwhile, such lawsuits are time-consuming and financially draining, and are also distract management attention from running the company

CANADIAN VERSUS U.S. ENERGY COMPANIES – A COMPARISON

Canadian energy companies, including pipelines and electricity companies, have generally not faced the problems that their U.S. counterparts have faced over the past two years. As a result, the credit ratings of Canadian energy companies have generally remained stable, while U.S. energy companies have generally had deteriorating credit quality. The following is a list of the factors that have contributed to the financial problems of U.S. energy companies, but have been, for the most part, less applicable to Canadian energy companies.

- Excessive mergers and acquisitions
- Aggressive expansion of merchant generation capacity
- New generation capacity mainly natural gas-fired
- Aggressive international expansion
- Telecommunications industry exposure
- Aggressive accounting
- Difficulty accessing capital from banks and capital markets
- Lawsuits: California-related and "round-tripping"
- High debt levels
- High-risk trading activities

Issue	U.S. Companies	Canadian Companies
Excessive mergers and acquisitions	Many mergers occurred throughout the U.S., as smaller entities combined forces. Mergers have caused disruptions, as regulatory approval delays were often lengthy, and deflected management attention from daily operations.	Alberta and Ontario have separated generation, transmission, and distribution within their electricity industries. Few mergers have occurred in Canada, given that only these two provinces have restructured their electricity industries.
Aggressive expansion of merchant generation capacity	Massive generation capacity additions, with natural gas as the primary fuel source, have resulted in the current over-capacity situation. Many plants lack long-term contracts or matched fuel and power contracts. Many announced projects have been, and are being, cancelled.	Aggressive expansion in Alberta, a booming province with very little inter-provincial transmission capacity in or out. In Ontario, 3,500 MW of laid up nuclear capacity is being refurbished, equal to six to seven years of demand growth in the province. This is expected to keep power rates near Cdn$40 to $45/MWh through to 2006. Limited new thermal capacity coming on in Ontario should also ensure stable rates.
New merchant generation capacity mainly natural gas-fired	Virtually all newly built generation capacity has been natural gas-based. Natural gas and crude oil are among the most expensive fuel sources. Therefore, as demand rises (in the summer air-conditioning and winter heating seasons), natural gas-fired plants will be used as intermediary and peaking plants – not for base load. Gas-fired plant usage has been much less than previously expected, with plants better suited as peaking units.	Alberta has substantial natural gas reserves, so future generation expansion is likely to be natural gas-fired. However, large coal-based generation is highly efficient and comprises most of the generation capacity in the province. Ontario's next 3,500 MW of generation capacity is return to market of nuclear-based plants to come on line in 2003.

Issue	U.S. Companies	Canadian Companies
Aggressive international expansion	Many companies have projects throughout Asia, Latin America, Africa, Eastern Europe, and especially in U.K. distribution and Australia. Few international investments have been successful, and many are being liquidated below cost.	Very limited. TransCanada PipeLines expanded internationally in the late 1990s, but started selling assets in 2000 at peak prices and has little international exposure now. Canadian international exposure remains small, with currency, political and regulatory risks minimized. However, selective purchases have begun (e.g., Enbridge and TransAlta).
Telecommunications industry exposure	Many energy companies have offered broadband services to business for data and wholesale carriers for capacity. Transmission line right of way and railway lines used to build network supplemented by leased lines. Losses build sharply as size rises.	There is very little exposure to telecommunications third parties in Canada. Mainly used for in house communication. Ontario municipal electricity companies, have been increasing their exposures, but the activity remains limited.
Aggressive accounting	Extensive use of off-balance sheet transactions, special purpose entities to transfer assets, debt, and risk. Aggressive booking of revenue. Use of FASB 133 influences stability of income. "Round-tripping" or "wash" trades also hurt credibility of some energy companies.	Use of limited partnerships to help finance acquisitions, but no support or backup from the parent. Generally, not aggressive traders, and much more conservative in future revenue recognition. Little "round-tripping" or "wash" trading.
Difficulty accessing capital from banks and capital markets	Some of the highly leveraged companies are having difficulty renewing bank lines. Security and onerous covenants are required in some cases.	Canadian energy companies are having little difficulty renewing bank lines and generally have ready and open access to the capital markets.
Lawsuits	Major lawsuits with respect to the California energy crisis in 2000-01, and effects of "wash trading" and round tripping. Companies may be in the courts for five to ten years over these lawsuits, with costly lump sum settlements possible.	Limited exposure to either California or round-tripping trading litigation.
High debt levels	Aggressive expansion resulted in debt to capital ratios of 60% to 70%+, which is too high for merchant power companies. Goodwill and asset write-downs also reduce the companies' equity bases.	Most Canadian energy companies have a good base of regulated operations, and key financials consistent with DBRS standards: 50% to 60% debt/capital, cash flow/debt of 0.10 times to 0.15 times, and EBIT coverage of 2 times to 3 times.
Trading activities	Rating cuts to non-investment grade status have reduced the number of energy companies with which market participants will trade. Severe cutbacks are occurring, from which it will take several years to recover.	Canadian companies have not been major traders, and their strategies usually are low/moderate risk. Companies like OPG and Hydro-Québec have the fundamentals to become extensive traders, in the low- to moderate-risk range. Hydro-Québec, with a hydro generation base, ample water storage, and good transmission interconnections to the U.S., could become a formidable low-risk trader.

Appendix D: World Natural Gas Market Trends

WORLD NATURAL GAS PRODUCTION*

(Billion cubic feet per day)	Change 2001 over 2000	% of total 2001	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991
U.S.	1.9%	22.5%	53.0	51.9	51.6	52.1	51.8	51.5	51.0	51.6	49.6	48.7	48.5
Canada	**2.5%**	**7.0%**	**16.6**	**16.2**	**15.7**	**15.5**	**15.1**	**14.8**	**14.3**	**13.1**	**12.1**	**11.2**	**10.2**
Mexico	-6.3%	1.4%	3.4	3.6	3.7	3.5	3.3	3.0	2.7	2.8	2.7	2.7	2.7
Total North America	**1.6%**	**30.9%**	**73.0**	**71.7**	**71.0**	**71.1**	**70.2**	**69.3**	**68.0**	**67.5**	**64.4**	**62.6**	**61.4**
South & Central America	3.7%	4.1%	9.6	9.4	8.7	8.5	8.0	7.7	7.1	6.5	6.3	5.9	5.9
Europe	1.2%	11.9%	29.1	28.7	28.1	27.4	27.7	28.1	24.9	24.3	24.1	23.0	22.9
Former Soviet Union	0.4%	27.5%	69.1	68.7	67.0	65.8	64.1	68.1	67.3	68.5	72.4	74.4	77.3
Middle East	6.7%	9.3%	22.1	20.5	18.8	17.7	17.0	15.3	14.4	13.1	11.9	11.0	10.0
Africa	-0.5%	5.0%	12.0	11.9	11.3	10.2	9.6	8.6	8.2	7.3	7.8	7.2	7.0
Asia Pacific	2.4%	11.4%	27.0	26.4	25.0	23.3	22.9	21.9	20.5	19.3	17.9	16.9	15.9
Total World	**1.7%**	**100.0%**	**241.9**	**237.3**	**229.9**	**224.0**	**219.5**	**219.0**	**210.4**	**206.5**	**204.8**	**201.0**	**200.4**
Of which European Union	0.6%	8.6%	21.5	21.2	20.8	20.5	20.6	21.4	19.1	18.4	18.1	17.0	16.8
OECD	1.8%	43.8%	104.7	102.6	101.2	100.7	99.7	99.1	94.4	93.0	89.2	86.1	84.4
Former Soviet Union	0.4%	27.5%	69.1	68.7	67.0	65.8	64.1	68.1	67.3	68.5	72.4	74.4	77.3
Other EMEs	3.0%	28.7%	68.3	66.2	61.7	57.8	55.8	51.8	48.6	44.9	42.9	40.5	38.7

* Production excludes gas flared or recycled.

Note: Annual changes and shares of total are based on data expressed in tonnes oil equivalent OECD = Organization for Economic Co-operation and Development

As the data above are derived from tonnes oil equivalent using average conversion factors, they do not necessarily equate with gas volumes expressed in specific national terms

Because of rounding some totals may not agree exactly with the sum of their component parts EME = Emerging Market Economies

Source: BP Statistical Review of World Energy – June 2002.

Total world natural gas production rose by 1.7% in 2001, and by 20.7% in 1991-2001. However, due to the high relative cost of transportation, natural gas markets tend to be regional/continental in nature. Therefore, large surpluses in one market (e.g., the former Soviet Union) cannot be economically shipped to deficit markets (e.g., the U.S.)

North American natural gas production rose by 1.6% in 2001, and by 18.9% between 1991 and 2001. U.S. gas production was flat at 52 Bcf/d in 1994-2000, before rising by 1.9% in 2001, largely due to substantial drilling activity after a record gas price spike by the end of 2000. Canada's production grew by more than 3.5 Bcf/d (27%) in 1994-2001, with offshore east coast production providing part of the increase in 2000-01.

WORLD NATURAL GAS CONSUMPTION

(Billion cubic feet per day)	2001 over 2000	share of total	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991
U.S.	-4.8%	25.6%	59.6	62.4	60.2	59.4	61.0	61.0	60.0	57.7	56.4	54.4	53.1
Canada	**-6.4%**	**3.0%**	**7.0**	**7.5**	**7.0**	**6.8**	**7.2**	**7.2**	**6.9**	**6.9**	**6.6**	**6.4**	**6.1**
Mexico	-3.3%	1.4%	3.3	3.4	3.3	3.3	3.1	3.0	2.9	2.8	2.7	2.7	2.7
Total North America	**-4.9%**	**30.0%**	**69.9**	**73.3**	**70.5**	**69.5**	**71.3**	**71.2**	**69.8**	**67.4**	**65.7**	**63.5**	**61.9**
South & Central America	4.1%	4.0%	9.4	9.0	8.4	8.6	8.2	7.7	7.1	6.5	6.3	6.0	5.7
Former Soviet Union	0.3%	22.8%	53.1	52.7	51.7	51.3	50.2	53.7	53.0	54.9	59.0	60.6	64.5
Middle East	4.5%	8.4%	19.4	18.7	17.5	16.7	16.0	14.6	13.8	12.6	11.5	10.7	9.4
Africa	8.2%	2.5%	5.8	5.4	4.9	4.6	4.5	4.6	4.3	4.0	3.8	3.6	3.3
Asia Pacific	5.0%	12.7%	29.3	28.3	26.5	24.3	23.9	22.7	20.9	19.7	18.3	17.3	16.3
Total World	**0.3%**	**100.0%**	**232.4**	**231.9**	**222.5**	**216.6**	**214.1**	**215.4**	**205.9**	**199.4**	**198.9**	**194.0**	**194.1**
Of which European Union 15	1.5%	15.9%	36.8	36.4	35.2	33.7	32.2	32.5	29.3	27.2	27.1	25.4	25.8
OECD	-1.5%	53.9%	125.4	127.3	122.4	119.0	118.7	118.8	112.8	107.5	104.9	100.4	99.1
Former Soviet Union	0.3%	22.8%	53.1	52.7	51.7	51.3	50.2	53.7	53.0	54.9	59.0	60.6	64.5
Other EMEs	4.8%	23.3%	53.9	51.9	48.4	46.3	45.2	42.9	40.1	37.0	35.0	33.0	30.5

Notes: The difference between these world consumption figures and the world production statistics is due to variations in stocks at storage facilities and liquefaction plants, together with unavoidable disparities in the definition, measurement, or conversion of gas supply and demand data

Annual changes and shares of total are based on data expressed in tonnes oil equivalent

As the data above are derived from tonnes oil equivalent using average conversion factors, they do not necessarily equate with gas volumes expressed in specific national terms OECD = Organization for Economic Co-operation and Development EME = Emerging Market Economies

Source: BP Statistical Review of World Energy – June 2002.

In 2001, world natural gas consumption increased by 0.3%, compared to 4.1% in 2000 and 2.7% in 1999. Overall, natural gas consumption increased in all regions (except North America and OECD) in 2001.

North American gas consumption declined in 2001, mainly due to a 4.8% drop in the U.S. (which accounted for 85% of North American consumption), following increases of 3.5% in 2000, and 1.3% in 1999.

Much of the increased usage in 1999 and 2000, was related to strong economic growth, and surging gas-fired electricity demand. In 2001, high natural gas prices, and a weakening economy resulted in lower demand, and substitution towards coal- and nuclear-based electricity generation.

For industrialized regions where gas markets are most mature, gas is expected to generate the greatest incremental increase in energy consumption. This is largely due to the increasing share of natural gas used in electricity generation, where gas-fired turbine power plants offer some of the highest commercially available plant efficiencies, and are also attractive as a way to reduce greenhouse gas emissions.

North American Natural Gas: Consumption minus Production

(Billion cubic feet per day)	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991
U.S.	**(6.6)**	**(10.5)**	**(8.6)**	**(7.3)**	**(9.2)**	**(9.5)**	**(9.0)**	**(6.1)**	**(6.8)**	**(5.7)**	**(4.6)**
Canada	9.6	8.7	8.7	8.7	7.9	7.6	7.4	6.2	5.5	4.8	4.1
Mexico	0.1	0.2	0.4	0.2	0.2	0.0	(0.2)	0.0	0.0	0.0	0.0
Total North America	**3.1**	**(1.6)**	**0.5**	**1.6**	**(1.1)**	**(1.9)**	**(1.8)**	**0.1**	**(1.3)**	**(0.9)**	**(0.5)**
U.S.: Prod'n/Consumption	89%	83%	86%	88%	85%	84%	85%	89%	88%	90%	91%

Source: BP Statistical Review of World Energy – June 2002

The U.S. depends on imported natural gas. While Canada, and to a lesser degree Mexico, have excess production available for export, the U.S. required 6.6 Bcf/d of imports to meet its internal consumption needs in 2001, although external requirements were much higher in prior years. In other words, U.S. production was able to satisfy only 89% of internal demand in 2001, the highest level of self-sufficiency since 1992.

U.S. external needs are likely to grow, however, given a likely production decline in 2002, and resumption of consumption growth. Since natural gas markets are regional/continental in nature, this demand can be met economically from limited sources. There are few large potential sources of natural gas that can be accessed over the medium term, to meet anticipated demand. This will likely translate into natural gas price spikes (e.g., in 2000-01) over the near to medium term.

Select Benchmark Natural Gas Prices (US$ / mmbtu)

(US$ per million Btu)	U.S. Henry Hub‡	Yr/Yr. % chg.	Canada (Alberta) ‡	Yr/Yr. % chg.	Differential U.S. - Canada	Yr/Yr. % chg.
1991	1.49	-9.3%	0.89	-15.4%	0.60	1.7%
1992	1.77	19.2%	0.98	10.2%	0.79	32.5%
1993	2.12	19.7%	1.69	72.9%	0.43	-46.0%
1994	1.92	-9.5%	1.45	-14.2%	0.47	9.1%
1995	1.69	-12.2%	0.89	-38.7%	0.80	70.4%
1996	2.76	63.4%	1.12	25.9%	1.64	105.3%
1997	2.53	-8.4%	1.36	21.2%	1.17	-28.7%
1998	2.08	-17.5%	1.42	4.7%	0.66	-43.3%
1999	2.27	**8.7%**	2.00	**40.3%**	0.27	**-59.2%**
2000	4.23	**86.5%**	3.75	**87.8%**	0.48	**77.2%**
2001	4.07	**-3.7%**	3.61	**-3.6%**	0.46	**-4.5%**

†Source: PH Energy. ‡Source: Natural Gas Week.

Note: cif = cost+insurance+freight (average prices)

Source: BP Statistical Review of World Energy – June 2002

Natural gas prices are set in regional markets, with differences in benchmark prices primarily resulting from differing delivery points and transportation costs, as well as the supply/demand conditions in each region.

Natural gas prices rose sharply in Canada in 1999-2000, and in the U.S. in 2000, before declining marginally in both markets in 2001.

U.S. Henry Hub Prices

Average natural gas prices at the Henry Hub (in Oklahoma) rose 87% to US$4.23/mmbtu for 2000, from US$2.27/mmbtu for 1999, mainly due to: (1) rising demand from a strong U.S. economy, combined with lagging domestic production despite increased gas related drilling activity; (2) high crude oil prices (which deters fuel switching); and (3) increases in summer power generation demand, which constrained inventory buildup during the refill season.

In 2001, the U.S. economy began to slow, while very high natural gas prices early in the year led to lower demand, and substitution towards coal- and nuclear-based electricity generation. Consequently, natural gas prices fell through the year. During the first nine months of 2002, Henry Hub natural gas averaged US$3.05/mmbtu, compared to US$4.47/mmbtu in 9M/01, a 32% decline, mainly due to slow economic growth and relatively high storage levels. Prices have been in the low US$4.00/mmbtu range in October 2002 to November 2002, partly due to seasonal factors.

Alberta (AECO) Prices

Unlike Henry Hub prices, Alberta natural gas spot prices began to rise significantly in 1999. This reflected anticipation of completion of the Alliance pipeline in December 2000, resulting in an additional 1.325 Bcf/d of incremental export pipeline capacity to Chicago.

Previously, Alberta gas prices were dampened by the "supply glut" caused by insufficient pipeline export capacity, a problem solved by the commencement of Alliance.

During the first nine months of 2002, AECO natural gas averaged US$2.28/mmbtu, compared to US$3.97/mmbtu in 9M/01, a 74% decline, mainly due to slow economic growth, warmer-than-normal weather, and relatively high storage levels. Prices have been in the low-to-mid US$3.00/mmbtu range in October 2002 to November 2002, partly due to seasonal factors.

Average Henry Hub/Alberta Natural Gas Spot Price Differential

Natural gas price differentials between Henry Hub and Alberta have fallen significantly since 1996-97 as export pipeline capacity constraints in Alberta were eliminated by the commencement of Alliance Pipeline.

The basis differential between Henry Hub and Alberta averaged only US $0.40/mmbtu for 1999-2001 compared to $1.16/mmbtu in 1996-98. Differentials, which increased to nearly $0.77/mmbtu during 9M/02, are generally close to transportation costs (i.e., pipeline tolls), indicating that the markets are relatively well balanced.

Natural Gas Price Outlook:

Over the medium to long term, DBRS expects average North American natural gas prices to remain in the higher ranges established beginning in 2000 (i.e., US$3.50/mmbtu to US$4.50/mmbtu) with intermittent spikes outside the range on both the upside and the downside. Low natural gas prices experienced before 1999, are not likely to return. Factors contributing to the strong outlook for natural gas in North America include:

Demand Factors:

(1) Once the U.S. economy recovers, the upward trend in natural gas consumption is likely to resume, supported by rising industrial demand. U.S. natural gas demand has been rising at a steady pace (up 17.5% between 1991 and 2000), despite the drop in consumption in 2001.

(2) Despite current weakness, U.S. gas demand growth over the medium term will be driven by construction of gas-fired electricity plants to replace coal- and nuclear-fired plants. This trend is supported by the more stringent power plant emission standards beginning in May 2003. Natural gas is an environmentally desirable fuel compared to alternative energy sources.

Seasonal factors also affect natural gas demand, with colder weather in winter (for space heating) and warmer weather in summer (for air conditioning) supporting higher prices.

Supply Factors:

(1) So far in 2002, U.S. natural gas-related drill rig activity has declined substantially, likely resulting in a return to the 52 Bcf/d production level experienced from 1994 to 2000. In 2001, despite record drilling activity, U.S. production increased to only 53 Bcf/d, far below U.S. consumption levels (59.6 Bcf/d in 2001). High production decline rates (especially in the Gulf of Mexico) are difficult to overcome.

(2) Western Canadian natural gas drilling activity has also declined (-29% for both crude oil and natural gas in 9M/02), while domestic consumption could resume its 1998-2000 rising trend. This implies that WSCB shipments to the U.S. will not grow quickly enough to meet U.S. demand.

(3) New frontier supplies are unlikely to meet the growing demand/supply gap until late in this decade. Regulatory delays and substantial economic hurdles are delaying the delivery of northern natural gas (e.g., Mackenzie Delta and Alaskan gas), while liquefied natural gas is likely to provide only a marginal impact on supply

Section A – Operating & Statistical Data

Table 1 (a): Installed Generating Capacity (MW)							
Companies*	As at						
Government-Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	11,102	11,102	11,133	11,123	11,045	10,999	10,829
Hydro-Québec	31,172	31,172	31,512	31,505	31,472	31,397	31,413
Manitoba Hydro	5,185	5,185	5,221	5,124	5,148	5,152	5,231
NB Power	3,769	3,769	3,775	3,919	3,919	3,919	3,909
Newfoundland and Labrador Hydro	1,601	1,601	1,599	1,599	1,602	1,602	1,602
Saskatchewan Power	2,880	2,880	2,889	2,889	2,748	2,748	2,748
Churchill Falls (1)	5,653	5,653	5,653	5,653	5,653	5,653	5,653
Group Total	61,362	61,362	61,782	61,812	61,587	61,470	61,385
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	188	205	205	205	205	205	205
CU Inc.	1,162	1,162	1,312	1,388	1,387	1,452	1,446
EPCOR Utilities	1,881	1,881	1,701	1,701	1,701	1,701	1,701
Newfoundland Power	148	148	148	148	148	147	147
Great Lakes Power	1,042	704	680	650	499	488	486
Ontario Power Generation (2)	24,168	24,717	30,819	30,819	30,892	30,423	30,423
Nova Scotia Power	2,183	2,183	2,183	2,183	2,183	2,183	2,183
TransAlta Utilities	4,519	4,476	4,476	4,476	4,471	4,471	4,471
Group Total	35,291	35,476	41,524	41,570	41,486	41,070	41,062
Industry Total	**96,653**	**96,838**	**103,306**	**103,382**	**103,073**	**102,540**	**102,447**
Holding Companies (consolidated)							
Canadian Utilities (3)	1,960	1,886	1,980	1,902	1,869	1,774	1,768
Emera Inc. (4)	2,183	2,183	2,183	2,183	2,183	2,183	2,183
Fortis Inc. (5)	389	352	373	275	252	251	251
TransAlta Corp. (6)	7,528	6,998	6,870	5,940	5,484	5,308	5,291

(1) Includes 225-MW of installed capacity at Twin Falls.

(2) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro. Total capacity for OPG includes Pickering A 2,060 MW laid-up for refurbishment.

(3) Canadian Utilities owns CU Inc.

(4) Emera owns Nova Scotia Power.

(5) Fortis owns Newfoundland Power.

(6) TransAlta Corp. owns TransAlta Utilities.

* This table does not apply to transmission and distribution companies.

- There has been very little new generation capacity added in Canada in recent years by the rated companies above
- Most new capacity has come from independent power projects (IPPs) in Alberta, Saskatchewan, and Ontario
- Including the IPPs in Alberta, Saskatchewan, Ontario, and Québec, and the in-service capacity of the Bruce B nuclear generation plant leased to Bruce Power, the total generation capacity in Canada remained at about 108,000 MW in 2002
- The reduction in Ontario Power Generation's installed capacity in 2001 reflects the transfer of control of the Bruce A and Bruce B nuclear generation plants to Bruce Power through a long-term lease agreement, and the reduction in 2002 reflects the sale of the Mississagi hydro plants to Great Lakes Power
- A limited amount of new generation capacity is currently under development, as most types of generation are not economic
- Most new generation capacity is being built in Alberta, Québec (primarily by Hydro-Québec) and Ontario (including laid-up capacity being refurbished)
- The political intervention that has occurred in Ontario has not directly impacted the wholesale market, but it has created increased uncertainty with respect to the future operation of the market

Table 1 (b): Peak Demand/Installed Capacity by Province for 2002

	Peak Demand (MW) (estimate for some)	Installed Capacity (MW)	Peak Demand/ Installed Capacity
British Columbia	8,692	11,100	78.3%
Alberta	8,570	10,900	78.6%
Saskatchewan	2,822	3,468	81.4%
Manitoba	3,760	5,203	72.3%
Ontario (1)	25,496	27,542	92.6%
Québec (2)	32,000	41,000	78.0%
New Brunswick	2,800	3,986	70.2%
Nova Scotia	1,800	2,267	79.4%
P.E.I.	195	104	187.5%
Newfoundland & Labrador	1,870	2,435	76.8%

(1) Includes in-service capacity only.
(2) Includes installed capacity at Churchill Falls (5,428 MW).

- The above table showing peak demand relative to installed capacity suggests that most provinces have more than sufficient capacity
- However, it should be noted that because much of the installed generation capacity in hydro-based, which is sensitive to the amount of rainfall and snow pack. Thus, the capacity factor of the actual installed capacity is much lower than if all the capacity was entirely coal-, gas, or nuclear-based
- Hydro-based generation is not always available to meet the peak demand
- New Brunswick's available capacity to meet peak demand is currently being constrained by operational problems at Point Lepreau (which is susceptible to unplanned outages)
- Excluding P.E.I., which imports most of its power, Ontario is currently in the tightest supply/demand position. This should, however, be remedied once Bruce A and Pickering A begin to come back on line

Table 2: Interconnections by Province for 2002 (MW)

	Total	Details
British Columbia	3,700	appr. 1,100 MW with Alberta 2,600 MW with the U.S
Alberta	1,250	appr. 1,100 MW with British Columbia 150 MW with Saskatchewan
Saskatchewan	600	300 MW with Manitoba; 150 MW with Alberta 150 MW with US Basin Electric
Manitoba	2,800	appr. 2,050 MW with U.S. Midwest Independent System Operator; 300 MW with Ontario; 450 MW with Saskatchewan
Ontario	appr. 5,500	appr. 1,900 MW with Michigan; 2,000 MW with New York 1,200 MW with Québec; 300 MW with Manitoba 100 MW with Minnesota
Québec	6,825	appr. 1,200 MW with Ontario; 1,200 MW with New Brunswick 2,125 MW with New York; 2,300 MW with New England
New Brunswick	2,570	appr. 1,060 MW with Québec; 500 MW with Nova Scotia 810 MW with New England; 200 MW with P.E.I.
Nova Scotia	500	500 MW with New Brunswick
P.E.I.	200	200 MW with New Brunswick
Newfoundland & Labrador	5,500	5,500 MW from Labrador with Québec

Note: Certain inter-connection capacity numbers will not match between provinces due to differences in reporting import versus export capacity and winter versus summer capacity.

- Limited interconnection capacity remains a major problem for the transmission of electricity across jurisdictions
- Furthermore, not all the above interconnection capacity can be used at the same time, so effective capacity is about 10% to 20% below the levels shown
- In Canada, virtually all of the interconnections are north/south with the U.S., rather than east/west with neighbouring provinces
- Very little new interconnection capacity is currently under development, largely due to public opposition
- Construction of an additional 1,250 MW of interconnection capacity between Ontario and Québec has been postponed and is not expected to be available until at least 2007
- The proposed 950 MW interconnection link under Lake Erie connecting Ontario with either or both of Pennsylvania and Ohio is also on hold and will not likely be built until the uncertainty in the Ontario electricity market subsides

Table 3: 2001 Generation Mix (based on 2001 installed capacity)							
Companies*							
Government-Owned & Guaranteed	Coal (%)	Gas (%)	Hydro (%)	Nuclear (%)	Oil (%)	Total (%)	Capacity
BC Hydro	-	8.2%	90.2%	-	1.6%	100%	11,102
Hydro-Québec	-	-	92.7%	2.2%	5.1%	100%	31,172
Manitoba Hydro	-	4.5%	95.3%	-	0.2%	100%	5,185
NB Power	13.7%	-	23.5%	16.8%	46.0%	100%	3,769
Newfoundland and Labrador Hydro	40.3%	-	56.2%	-	3.5%	100%	1,601
Saskatchewan Power	57.4%	13.0%	29.6%	-	-	100%	2,880
Churchill Falls	-	-	100.0%	-	-	100%	5,653
Group Weighted Average	4.6%	2.5%	85%	2.1%	5.8%	100%	61,362
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	-	-	-	100.0%	-	100%	205
CU Inc.	86.7%	7.8%	-	-	5.5%	100%	1,162
EPCOR Utilities	53.2%	46.8%	-	-	-	100%	1,881
Newfoundland Power	-	31.6%	63.7%	-	4.7%	100%	148
Great Lakes Power	-	10.6%	89.4%	-	-	100%	704
Nova Scotia Power	58.3%	8.2%	17.5%	-	16.1%	100%	2,183
Ontario Power Generation (1)	31.0%	-	28.0%	32.0%	9.0%	100%	24,717
TransAlta Utilities	82.3%	-	17.7%	-	-	100%	4,476
Group Weighted Average	41.2%	3.6%	24.9%	22.9%	7.5%	100%	35,476
Industry Weighted Average	**18.0%**	**2.9%**	**63.0%**	**9.7%**	**6.4%**	**100%**	**96,838**
Holding Companies (consolidated)							
Canadian Utilities (2)	56.0%	43.3%	0.8%	-	-	100%	1,886
Emera Inc. (3)	58.0%	9.0%	17.0%	-	16.0%	100%	2,183
Fortis Inc. (4)	-	12.1%	53.6%	-	34.3%	100%	352
TransAlta Corp. (5)	72.7%	15.8%	11.5%	-	-	100%	6,998

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
Total capacity for OPG includes Pickering A 2,060 MW laid-up for refurbishment.
(2) Canadian Utilities owns CU Inc. (3) Emera owns Nova Scotia Power.
(4) Fortis owns Newfoundland Power. (5) TransAlta Corp. owns TransAlta Utilities.
* This table does not apply to transmission and distribution companies.

- The generation mixes for the various utilities have remained relatively stable in recent years
- BC Hydro, Hydro-Québec, and Manitoba Hydro continue to generate over 90% of their electricity from hydro
- New Brunswick Power's generation is mainly oil-based
- Coal-based generation is dominant in Alberta, Saskatchewan and Nova Scotia, although gas-based generation has significantly increased in importance in Alberta
- Natural gas has historically not been a major fuel source for electricity generation in Canada, but is now the fastest growing component when taking into consideration IPPs
- Many generators are now being built for peaking purposes and this characteristic will increasingly influence the above numbers
- Although gas generation will rise in proportion to future capacity, most of the gas-based capacity is for peaking purposes. Consequently, although gas generation will account for a growing proportion of capacity, its proportion of generated power will not rise substantially

Table 4 (a): Gross Electricity Generated (millions of kWh)							
Companies*	12 months ended						
Government-Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	43,663	49,885	51,581	50,677	51,779	53,828
Hydro-Québec	n/a	149,668	152,800	142,400	131,700	141,726	147,692
Manitoba Hydro	n/a	31,537	31,567	29,044	29,252	33,107	30,909
NB Power	n/a	19,054	18,818	17,123	20,099	17,242	14,795
Newfoundland and Labrador Hydro	n/a	6,100	6,025	5,756	5,556	6,197	6,047
Saskatchewan Power	n/a	14,900	16,451	17,285	17,600	17,429	17,100
Churchill Falls	n/a	33,013	35,250	34,611	37,651	33,878	29,103
Group Total	nmf	297,935	310,796	297,800	292,535	301,358	299,474
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	1,625	1,510	1,489	1,494	1,507	1,549	1,425
CU Inc.	8,872	9,443	8,724	8,527	8,904	9,029	8,220
EPCOR Utilities	n/a	9,710	10,775	9,863	10,605	8,848	9,113
Newfoundland Power	n/a	416	423	450	429	424	423
Great Lakes Power	n/a	3,236	3,226	3,021	2,945	2,896	2,700
Nova Scotia Power	n/a	11,367	11,137	10,668	10,264	9,963	9,571
Ontario Power Generation (1)	115,700	121,600	136,200	131,101	125,980	131,017	134,278
TransAlta Utilities	29,664	28,370	28,122	28,717	29,769	30,353	29,598
Group Total	nmf	185,652	200,096	193,841	190,403	194,079	195,328
Industry Total	**nmf**	**483,587**	**510,892**	**491,641**	**482,938**	**495,437**	**494,802**
Holding Companies (consolidated)							
Canadian Utilities (2)	13,206	13,843	12,385	12,239	11,375	11,377	10,525
Emera Inc. (3)	n/a	11,367	11,137	10,668	10,264	9,963	9,571
Fortis Inc. (4)	n/a	1,055	1,041	997	429	424	423
TransAlta Corp. (5)	45,369	44,136	40,644	37,771	39,001	36,401	34,264

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) Canadian Utilities owns CU Inc.
(3) Emera owns Nova Scotia Power.
(4) Fortis owns Newfoundland Power.
(5) TransAlta Corp. owns TransAlta Utilities.
* This table does not apply to transmission and distribution companies.
n/a = not available, NA = not applicable, nmf = not meaningful.

- Electricity generated in Canada has typically been influenced by:
  - the amount of rainfall and water levels in British Columbia, Manitoba, and Québec;
  - the state of Ontario’s nuclear facilities; and
  - the amount of new generation capacity
- In 2001 and 2002, lower water levels reduced the amount of electricity generated in British Columbia and Québec
- Ontario Power Generation’s electricity generated was down in both 2001 and 2002 due to the lease of Bruce B to Bruce Power and the sale of the Mississagi hydro plants to Great Lakes Power
- Over the 2002-2005 period, electricity generation will be influenced by:
  - 2,000 MW of generation capacity from Pickering A and 1,500 MW of capacity from Bruce A coming back on line;
  - several cogeneration projects in Alberta, Saskatchewan, and Ontario;
  - Hydro-Québec’s new 882 MW hydro-based Sainte-Marguerite-3 generating facility coming on line in 2003; and
  - the 450-MW addition to the existing Genesee Generating Station in Alberta, expected to be operational in 2005

Table 4 (b): Gross Power Purchases (millions of kWh)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro*	n/a	29,837	27,346	23,634	19,100	9,296	5,950
Hydro-Québec*	n/a	58,758	50,680	42,712	44,337	34,307	29,199
Manitoba Hydro*	n/a	968	834	1,004	1,935	168	169
NB Power	n/a	1,945	2,092	4,712	2,568	3,148	3,908
Newfoundland and Labrador Hydro	n/a	2,551	2,545	2,538	2,382	932	878
Saskatchewan Power	n/a	3,818	3,686	1,811	1,536	982	529
Churchill Falls	-	-	-	-	-	-	-
Group Total	nmf	97,877	87,183	76,411	71,858	48,833	40,633
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	962	1,516	1,538	1,468	1,414	1,414	1,685
CU Inc.	1,362	666	1,668	1,526	1,283	1,060	1,557
EPCOR Utilities (2)	n/a	14,934	n/a	n/a	n/a	n/a	n/a
Great Lakes Power	n/a	1,993	1,784	561	534	557	501
Nova Scotia Power	n/a	279	295	411	242	340	255
Ontario Power Generation (1)	13,100	18,600	3,600	5,799	5,762	3,079	1,834
TransAlta Utilities	-	-	514	561	534	557	501
Group Total	nmf	37,988	9,399	10,327	9,769	7,007	6,333
Transmission & Distribution							
Altalink (3)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	NA	NA	NA	NA	NA	NA	NA
Enersource Corporation	7,566	7,249	7,002	6,821	6,505	6,288	6,149
ENMAX Corporation	9,678	9,242	7,500	7,262	6,980	6,867	6,644
Hydro One	26,700	21,300	17,600	18,100	18,300	18,800	18,600
Hydro Ottawa (4)	5,646	7,351	7,006	7,061	6,733	6,746	6,792
Newfoundland Power	n/a	4,495	4,432	4,292	4,259	4,244	4,236
Toronto Hydro	26,423	25,722	25,422	25,339	24,718	24,804	24,656
Veridian Corporation	2,385	2,232	2,160	2,123	n/a	n/a	n/a
Group Total	nmf	77,591	71,122	70,998	67,495	67,749	67,077
Industry Total	**nmf**	**213,456**	**167,704**	**157,736**	**149,122**	**123,589**	**114,043**

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes power purchases for export/trading purposes.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) Beginning on January 1, 2001, all of EPCOR's retail sales were supplied by purchased power. For years prior to 2001, self-generated power supplied the majority of retail sales requirements.
(3) Altalink began its operations in April 2002. (4) For the nine months ended September 30, 2002.

- Gross power purchased has grown over the past four years due to:
  - increased trading/exporting, particularly for BC Hydro and Hydro-Québec;
  - the introduction of retail competition in Alberta, which has resulted in much higher reported power purchase numbers for the companies involved in retail marketing; and
  - tight supply/demand conditions, as is the case for Saskatchewan Power
- Reported power purchases for Ontario Power Generation jumped sharply in 2001 due to the lease of the Bruce B generating facility and the subsequent repurchase of the electricity from Bruce Power prior to the opening of the competitive market
- Power purchases is a “trading” function for most Canadian integrated electric utilities that, as a matter of policy in the past, built enough generation capacity to be self-sufficient 100% of the time
- Although this policy is changing, most Canadian electric utilities are still 100% self-sufficient in generation
- Distribution companies do not generate their own power and, therefore, must purchase all of the power to serve their distribution customers
  - For distribution companies operating in retail competitive markets, power purchases are reported only for those companies offering the standard supply option to their customers and where the customer has chosen the option

Table 4 (c): Transmission Losses and Internal Uses as a Per Cent of Energy Generated & Purchased

Companies*	As at					
Government-Owned & Guaranteed	2001	2000	1999	1998	1997	1996
BC Hydro	6.8%	6.7%	6.8%	7.6%	7.6%	8.9%
Hydro-Québec	6.4%	6.6%	7.2%	8.3%	7.7%	7.6%
Manitoba Hydro	11.7%	11.3%	11.2%	11.2%	11.5%	11.3%
NB Power	9.2%	9.7%	9.1%	9.1%	8.9%	10.2%
Newfoundland and Labrador Hydro	3.6%	4.2%	3.7%	4.4%	4.9%	4.9%
Saskatchewan Power	9.7%	15.3%	15.0%	15.4%	15.2%	15.6%
Churchill Falls	2.0%	1.8%	2.3%	2.1%	2.2%	2.4%
Group Average	7.1%	7.9%	7.9%	8.3%	8.3%	8.7%
Integrated/Investor-Owned/No Gov't. Guarantee						
Aquila Networks Canada (BC)	9.7%	10.2%	10.7%	10.4%	11.3%	11.3%
CU Inc.	n/a	1.3%	1.8%	2.8%	2.8%	2.3%
EPCOR Utilities	NA	7.1%	7.3%	7.0%	7.5%	8.9%
Newfoundland Power	5.2%	6.6%	5.4%	5.6%	5.2%	5.3%
Great Lakes Power	n/a	n/a	n/a	n/a	n/a	n/a
Nova Scotia Power	6.4%	6.8%	6.4%	7.0%	7.6%	6.9%
Ontario Power Generation (1)	n/a	n/a	n/a	2.8%	3.5%	4.0%
TransAlta Utilities	NA	NA	5.9%	8.7%	7.9%	7.5%
Group Average	7.1%	6.4%	6.2%	6.3%	6.5%	6.6%
Industry Average	7.1%	7.2%	7.1%	7.3%	7.4%	7.6%

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

* This table does not apply to transmission and disribution companies. n/a = not available, NA = not applicable.

- Average power used and lost in transmission averaged just over 7% in 2001, about unchanged from the previous year. However, the reporting of line losses has changed significantly in recent years, with companies operating in competitive markets no longer reporting the number as it is the purchaser of the power that is responsible for line losses
- About 2% to 4% of electricity generated is lost in distribution
- Transmission losses remain highest for Manitoba Hydro, Aquila Networks Canada (BC) and Saskatchewan Power
- Saskatchewan Power experienced a significant improvement in line losses in 2001 due to improvements in the transmission grid
- In Canada, generation tends to be located in the northern regions of a province, while consumption tends to be in the south. Thus, transmission lines must travel across long distance across, which raises the degree of line losses
- Utilities with generation closer to where electricity is consumed have much lower electricity losses

Table 5 (a): Electricity Sales*/Distribution Volume Throughputs (millions of kWh)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	68,467	72,031	69,852	64,506	56,460	54,484
Hydro-Québec	n/a	195,026	190,080	171,712	161,373	162,533	163,402
Manitoba Hydro	n/a	29,214	28,806	26,688	27,692	29,462	27,567
NB Power	n/a	19,059	18,889	19,842	20,597	18,577	16,805
Newfoundland & Labrador Hydro	n/a	8,341	8,206	7,988	7,598	6,781	6,589
Saskatchewan Power	n/a	16,900	17,049	16,225	16,187	15,608	15,064
Churchill Falls	n/a	32,361	34,601	33,807	36,878	33,131	27,411
Group Total	nmf	369,368	369,662	346,114	334,831	322,552	311,322
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	2,834	2,731	2,717	2,624	2,617	2,628	2,759
CU Inc.	10,234	10,108	10,392	10,068	10,188	10,089	9,760
EPCOR Utilities	n/a	24,644	10,013	9,147	9,858	8,180	8,305
Great Lakes Power	5,845	4,199	4,159	3,582	3,479	3,453	3,201
Nova Scotia Power	11,100	10,906	10,656	10,365	9,772	9,516	9,146
Ontario Power Generation (1)	128,800	140,200	139,800	136,900	131,742	134,096	136,112
TransAlta Utilities	29,664	28,370	28,636	27,561	27,672	28,463	27,844
Group Total	188,477	221,158	206,373	200,247	195,328	196,425	197,127
Total of Two groups	**nmf**	**590,526**	**576,035**	**546,361**	**530,159**	**518,977**	**508,449**
Transmission & Distribution							
Altalink	na	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	23,563	23,641	7,909	NA	NA	NA	NA
Enersource Corporation	7,566	7,249	7,002	6,821	6,505	6,288	6,149
ENMAX Corporation	9,678	9,242	7,500	7,162	6,980	6,867	6,644
Hydro One (2)	26,700	21,300	17,600	18,100	18,300	18,800	18,600
Hydro Ottawa (3)	5,646	7,351	7,006	7,061	6,733	6,746	6,792
Newfoundland Power	4,720	4,667	4,555	4,500	4,440	4,438	4,425
Toronto Hydro	26,423	25,722	25,422	25,339	24,718	24,804	24,656
Veridian Corporation	2,385	2,232	2,160	2,123	n/a	n/a	n/a
Group Total	106,681	101,404	79,154	71,106	67,676	67,943	67,266
Holding Companies (consolidated)							
Canadian Utilities (5)	14,568	14,509	14,053	13,765	12,658	12,347	12,082
Emera Inc. (6)	11,565	11,371	10,656	10,365	9,772	9,516	9,146
Fortis Inc. (4)	6,805	6,608	6,450	6,378	4,440	4,438	4,425
TransAlta Corp. (7)	45,369	44,136	40,644	37,771	39,001	36,401	34,264

na = not available, NA = not applicable, nmf = not meaningful

* For CU Inc., represents distribution volume throughputs; for EPCOR Utilities, includes retail marketing sales beginning in 2001.
Prior to 2001, electricity sales=electricity generated for EPCOR.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Distribution throughput only.

(3) For the nine months ended September 30, 2002.

(4) Fortis owns Newfoundland Power.

(5) Canadian Utilities owns CU Inc. Electricity sales represent volume throughputs for CU Inc. plus electricity sales from IPPs.

(6) Emera owns Nova Scotia Power .

(7) Includes TransAlta Utilities. Electricity sales represent electricity generated.

- Electricity sales across Canada have typically grown at about 1% to 2% per year, and is largely dependent on economic growth
- Throughout the year, weather has a significant influence on electricity demand, given Canada's extreme temperature changes (i.e., winter/summer)
- With about 60% of generation in the country being hydro-based, annual output is influenced by the amount of rainfall and snow-pack levels during the year
- The reported group totals beginning in 2001 are influenced by the reporting of retail marketing sales in Alberta, resulting in some double counting as distribution volume throughputs are also included in the table for those distribution companies not offering standard supply

Table 5 (b): Exports as a Per Cent of Electricity Sold Companies*						
Government-Owned & Guaranteed	2001	2000	1999	1998	1997	1996
BC Hydro	30.2%	33.2%	33.5%	29.0%	23.3%	18.0%
Hydro-Québec	22.0%	19.6%	14.4%	11.5%	9.4%	11.6%
Manitoba Hydro	42.1%	42.2%	40.9%	41.2%	46.0%	41.7%
NB Power	27.6%	25.8%	31.5%	34.2%	25.7%	21.1%
Newfoundland and Labrador Hydro	18.7%	18.2%	21.7%	17.7%	0.0%	0.0%
Saskatchewan Power	13.0%	14.0%	12.3%	11.2%	9.8%	10.8%
Churchill Falls	87.0%	87.5%	87.8%	88.9%	91.5%	90.6%
Group Total	34.4%	34.4%	34.6%	33.4%	29.4%	27.7%
Integrated/Investor-Owned/No Gov't. Guarantee						
Aquila Networks Canada (BC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CU Inc.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
EPCOR Utilities	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Great Lakes Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nova Scotia Power	n/a	n/a	n/a	n/a	n/a	n/a
Ontario Power Generation (1)	2.6%	2.9%	3.3%	2.3%	4.8%	4.5%
TransAlta Utilities	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Group Average	nmf	nmf	nmf	nmf	nmf	nmf
Industry Average	nmf	nmf	nmf	nmf	nmf	nmf

n/a = not available, NA = not applicable=, nmf = not meaningful.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

* This table does not apply to transmission and distribution companies.

- Electricity exports have been growing as RTOs in the U.S. provide Canadian electric utilities with increased access to the U.S. markets
- The amount of electricity exported is dependent on:
  - Demand in the jurisdictions that purchase the exported power, which is influenced by the strength of the economy and temperature in that region; and
  - The supply available in the jurisdiction producing the exported power, which is largely dependent on hydrologic conditions (for hydro-based generation) and gas/oil/coal prices (for thermal-based generation)
- Churchill Falls exports almost all of its power to Hydro-Québec under a long-term contract
- Manitoba Hydro, with a small population base, is an export leader in Canada with 42% of its power exported
- BC Hydro (into Alberta and the U.S.) and NB Power (to P.E.I.) are also large exporters of electricity

Table 6 (a): Net Electricity Revenues ($ millions)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	4,160	6,236	7,830	3,427	2,997	2,497	2,377
Hydro-Québec	11,324	10,923	10,174	8,499	8,007	7,927	7,655
Manitoba Hydro*	1,342	1,374	1,261	1,113	1,074	1,036	1,018
NB Power	n/a	1,278	1,263	1,218	1,176	1,114	1,007
Newfoundland and Labrador Hydro	n/a	324	302	316	303	292	287
Saskatchewan Power*	1,111	1,126	1,080	957	940	902	871
Churchill Falls	n/a	94	96	93	94	87	80
Group Total	17,937	21,355	22,006	15,623	14,591	13,855	13,295
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	154	143	135	125	123	123	125
CU Inc. (2)	1,331	1,562	1,328	1,220	1,187	1,179	1,481
EPCOR Utilities (2)	1,217	1,224	915	621	603	547	532
Great Lakes Power	278	216	193	141	129	133	132
Nova Scotia Power	846	833	813	790	751	741	731
Ontario Power Generation (1)	6,044	6,239	5,753	5,579	5,795	6,592	6,652
TransAlta Utilities	751	846	578	772	854	1,129	1,197
Group Total	10,620	11,063	9,716	9,248	9,442	10,444	10,849
Transmission & Distribution							
Altalink**	75	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	250	243	72	NA	NA	NA	NA
Enersource Corporation	66	58	51	46	40	34	36
ENMAX Corporation	447	522	191	149	153	146	111
Hydro One (1)	2,204	2,199	2,136	2,186	1,883	1,849	1,911
Hydro Ottawa***	68	47	48	49	45	45	47
Newfoundland Power	159	157	147	147	141	150	146
Toronto Hydro	383	322	285	279	285	286	298
Veridian Corporation	29	22	19	19	18	18	na
Group Total	3,681	3,570	2,950	2,875	2,566	2,528	2,548
Industry Total	32,238	35,988	34,672	27,746	26,599	26,827	26,693
Holding Companies (consolidated)							
Canadian Utilities (3)	1,340	1,570	1,409	1,402	1,369	1,348	n/a
Emera Inc. (4)	1,161	915	813	790	751	741	731
Fortis Inc. (5)	601	566	524	460	437	449	432
TransAlta Corp. (6)	1,715	2,272	1,600	1,029	1,090	1,656	1,546

Net of trading/retail marketing power purchases. n/a = not available, NA = not applicable, nmf = not meaningful.
^For integrated govt owned & guaranteed, gross electricity revenues including trading/export revenue are reported.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) Includes non-electricity operations.
(3) Canadian Utilities owns CU Inc. Includes non-electricity operations.
(4) Emera owns Nova Scotia Power.
(5) Fortis owns Newfoundland Power.
(6) TransAlta Corp. owns TransAlta Utilities.
* 12 months ended June 30, 2002
** Six months ended October 2002.
*** Nine months ended September 2002.

- Electricity revenue growth for government-owned and guaranteed integrated utilities has generally been limited in recent years by rate freezes existing in many of provinces
- Strong export sales in 2001 and 2002 continued to offset some of the weakness in domestic markets for certain government-owned and guaranteed integrated utilities
- Investor-owned and non-government guaranteed integrated/generation utilities recorded increased revenues in 2001, with the Alberta-based utilities experiencing the largest increases as a result of the opening of the electricity market to competition on January 1, 2001
  - Generation subject to the legislatively mandated PPAs recorded significant increases in 2001 relative to 2000 due to the more favourable financial structure of the PPAs relative to the previous environment
  - In 2002, however, revenues have come down somewhat largely due to the lower electricity prices in Alberta compared to 2001
- Most of the distribution and transmission companies recorded higher revenues in 2001 and 2002 primarily due to volume growth:
  - ENMAX's electricity revenues are higher due to the combination of the opening of competitive marketplace in 2001, higher electricity prices and its participation in retail marketing

Table 6 (b): Exports as a Per Cent of Electricity Revenues						
Companies*						
Integrated Gov't. Owned & Guaranteed	2001	2000	1999	1998	1997	1996
BC Hydro	61.9%	61.9%	69.7%	32.9%	24.7%	na
Hydro-Québec	28.6%	23.4%	12.4%	10.2%	7.5%	7.7%
Manitoba Hydro	42.8%	38.1%	33.8%	30.4%	28.7%	26.3%
NB Power	28.1%	26.3%	27.1%	25.9%	21.9%	18.0%
Newfoundland and Labrador Hydro	9.5%	4.4%	12.2%	9.9%	0.0%	0.0%
Saskatchewan Power	11.1%	14.5%	16.7%	9.6%	7.7%	6.3%
Churchill Falls	91.1%	91.7%	91.5%	92.8%	95.6%	95.2%
Group Average (1)	39.0%	37.2%	37.6%	30.2%	26.6%	25.6%
Integrated/Investor-Owned/No Gov't. Guarantee						
Aquila Networks Canada (BC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CU Inc.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
EPCOR Utilities	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Great Lakes Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nova Scotia Power	na	na	na	na	na	na
Ontario Power Generation	2.7%	4.8%	4.2%	1.7%	2.0%	2.0%
TransAlta Utilities	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Group Average	nmf	nmf	nmf	nmf	nmf	nmf

* This table is not applicable to transmission and distribution companies.

n/a = not available, NA = not applicable, nmf = not meaningful.

(1) Total include some double counting: Churchill Falls exports to Hydro-Québec, and Hydro-Québec exports to the U.S.

- Exports sales remained a strong contributor to the electricity revenues of government-owned and guaranteed integrated utilities:
  - Export sales (in kWh), as evidenced in Table 5 (b), constituted between 20% and 40% of most government-owned and guaranteed integrated utilities' total electricity sales
- As export prices are higher than domestic prices, export sales contribute a significant margin to these utilities' net earnings

Table 7: Total Assets ($ millions)							
Companies	As at						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	12,061	11,966	12,615	11,596	11,685	11,305	11,456
Hydro-Québec	58,461	58,664	59,038	56,836	57,295	55,194	53,760
Manitoba Hydro*	10,261	10,405	9,966	8,692	7,866	7,617	7,133
NB Power	n/a	3,236	3,298	3,359	3,666	4,197	4,287
Newfoundland and Labrador Hydro	n/a	1,935	1,817	1,802	1,892	1,901	1,958
Saskatchewan Power*	3,575	3,592	3,224	3,093	3,067	3,132	3,332
Churchill Falls	n/a	654	676	693	741	751	771
Group Total	nmf	90,452	90,634	86,071	86,212	84,097	82,697
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	429	408	367	335	308	292	278
CU Inc.	3,737	3,865	4,281	3,580	3,538	3,391	3,354
EPCOR Utilities	4,634	4,542	3,093	2,357	2,229	2,195	2,122
Great Lakes Power	3,430	2,930	2,642	2,365	2,254	2,236	2,347
Nova Scotia Power	2,860	2,905	2,839	2,812	2,827	2,881	3,065
Ontario Power Generation (1)	17,008	16,686	16,632	15,610	40,023	39,181	39,870
TransAlta Utilities	3,676	4,071	3,040	3,309	3,272	3,384	3,573
Group Total	35,774	35,407	32,894	30,368	54,451	53,560	54,609
Transmission & Distribution							
Altalink	903	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	872	1,011	1,494	NA	NA	NA	NA
Enersource Corporation	642	560	524	569	518	491	473
ENMAX Corporation	1,315	1,390	1,130	540	545	517	509
Hydro One (1)	11,874	11,231	9,997	10,090	NA	NA	NA
Hydro Ottawa	554	519	501	491	476	451	442
Newfoundland Power	679	665	628	620	601	582	574
Toronto Hydro	2,489	2,046	2,067	1,961	1,943	2,042	2,025
Veridian Corporation	202	188	181	181	181	175	n/a
Group Total	18,626	17,611	16,522	14,451	4,264	4,258	4,023
Industry Total	nmf	143,470	140,049	130,890	144,927	141,915	141,329
Holding Companies (consolidated)							
Canadian Utilities (2)	5,523	5,392	5,390	5,429	4,437	4,091	3,937
Emera Inc. (3)	3,909	3,959	2,951	2,902	2,857	2,881	3,065
Fortis Inc. (4)	1,861	1,625	1,479	1,244	1,037	1,017	998
TransAlta Corp. (5)	7,397	7,572	7,627	5,932	5,393	4,882	5,014

n/a = not available, NA = not applicable, nmf = not meaningful.

* As at June 30, 2002.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Canadian Utilities owns CU Inc. (3) Emera owns Nova Scotia Power.

(4) Fortis owns Newfoundland Power. (5) TransAlta Corp. owns TransAlta Utilities.

- Total assets have generally grown at a slow pace, with the majority of growth coming from acquisitions
- Hydro-Québec, with assets near $60 billion, is by far the largest electric utility in Canada
- The public sector continues to account for the majority of electricity assets in Canada

Table 8: Accumulated Depreciation/Gross Fixed Assets

Companies	As at Sept. 2002	2001	2000	1999	1998	1997	1996
Integrated Gov't. Owned & Guaranteed							
BC Hydro	37.2%	36.9%	36.0%	34.8%	33.6%	32.5%	31.3%
Hydro-Québec	27.1%	25.6%	24.1%	22.9%	21.3%	19.8%	18.1%
Manitoba Hydro	n/a	30.0%	28.9%	27.7%	27.7%	26.8%	25.8%
NB Power	n/a	47.4%	45.4%	42.8%	40.0%	37.2%	31.6%
Newfoundland and Labrador Hydro	n/a	23.6%	23.2%	22.1%	21.1%	19.4%	17.9%
Saskatchewan Power	n/a	39.2%	38.9%	37.5%	36.0%	34.3%	32.6%
Churchill Falls	n/a	41.7%	40.2%	38.6%	36.8%	35.1%	33.4%
Group Average	nmf	34.9%	33.8%	32.3%	30.9%	29.3%	27.2%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	27.4%	28.0%	29.2%	29.8%	30.0%	30.4%	29.6%
CU Inc.	38.5%	38.0%	37.4%	36.4%	35.1%	34.0%	32.5%
EPCOR Utilities	n/a	26.7%	26.3%	26.5%	26.7%	25.5%	23.5%
Great Lakes Power	n/a	17.2%	17.3%	18.8%	20.3%	19.5%	18.9%
Nova Scotia Power	n/a	35.8%	34.5%	33.1%	31.9%	30.8%	29.8%
Ontario Power Generation	12.8%	10.2%	6.6%	2.9%	31.4%	29.3%	27.0%
TransAlta Utilities	45.5%	46.7%	46.1%	49.0%	47.8%	45.7%	43.9%
Group Average	nmf	28.9%	28.2%	28.1%	31.9%	30.7%	29.3%
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	63.2%	62.5%	61.7%	na	NA	NA	NA
Enersource Corporation	n/a	35.4%	33.9%	31.9%	32.2%	31.5%	30.5%
ENMAX Corporation	n/a	40.7%	43.4%	43.6%	43.1%	38.4%	37.3%
Hydro One	34.5%	33.6%	32.5%	31.5%	NA	NA	NA
Hydro Ottawa*	46.7%	47.6%	46.6%	45.4%	48.1%	45.9%	n/a
Newfoundland Power	41.7%	40.4%	40.8%	42.3%	41.7%	41.6%	40.3%
Toronto Hydro	n/a	41.4%	40.4%	38.7%	36.7%	35.6%	34.4%
Veridian Corporation	n/a	41.3%	41.7%	40.3%	38.7%	36.8%	n/a
Group Total	46.5%	42.9%	42.6%	39.1%	40.1%	38.3%	35.6%
Industry Average	nmf	35.6%	34.9%	33.2%	34.3%	32.8%	30.7%
Holding Companies (consolidated)							
Canadian Utilities (3)	40.1%	33.7%	34.2%	33.3%	32.1%	31.4%	30.1%
Emera Inc. (4)	n/a	33.8%	34.4%	33.1%	31.9%	30.8%	29.8%
Fortis Inc. (5)	n/a	32.6%	34.2%	35.8%	n/a	n/a	n/a
TransAlta Corp. (6)	25.6%	30.5%	32.0%	38.4%	43.4%	38.7%	38.1%

n/a = not available, NA = not applicable, nmf = not meaningful.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Altalink began its operations in April 2002.

(3) Canadian Utilities owns CU Inc.

(4) Emera owns Nova Scotia Power.

(5) Fortis owns Newfoundland Power.

(6) TransAlta Corp. owns TransAlta Utilities.

* Nine months ended September 2002.

- Accumulated deprecation accounts for about one-third of total assets
- Accumulated depreciation relative to gross fixed assets has generally been rising slowly over the past decade, particularly for those companies that are not on a growth track
- The more mature companies, ones that have experienced very low growth, tend to have the highest accumulated depreciation rate
- Companies that have been expanding rapidly such as Hydro-Québec, EPCOR Utilities, and TransAlta Corporation, have among the lowest
- Note:
  - Ontario Power Generation's accumulated depreciation/gross fixed assets is particularly low due to the $14 billion write-off upon the restructuring of the old Ontario Hydro, in 1999
  - Depreciation rates on generation plants in Canada tend to be lower than in the U.S. due to the dominance of hydro-based generating facilities, which have very long economic lives

Section B – Key Financial Ratios

Table 9 (a): Per Cent Adjusted Debt in the Capital Structure

Companies	As at Sept. 2002	2001	2000	1999	1998	1997	1996
Integrated Gov't. Owned & Guaranteed							
BC Hydro	81.8%	81.0%	80.3%	82.2%	85.2%	85.3%	86.1%
Hydro-Québec	72.9%	74.7%	73.6%	73.5%	74.8%	74.8%	75.6%
Manitoba Hydro*	83.0%	82.9%	85.3%	88.1%	89.5%	90.8%	92.4%
NB Power	n/a	105.3%	105.8%	103.0%	105.0%	91.3%	88.3%
Newfoundland and Labrador Hydro	n/a	68.2%	66.4%	63.1%	65.2%	68.1%	69.4%
Saskatchewan Power*	59.0%	60.0%	57.4%	57.8%	62.3%	62.6%	63.3%
Churchill Falls	n/a	43.3%	46.7%	49.5%	53.8%	55.2%	56.4%
Group Average	74.2%	73.6%	73.6%	73.9%	76.5%	75.4%	75.9%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	55.6%	57.4%	62.4%	59.1%	61.3%	59.1%	58.9%
CU Inc.	55.0%	54.9%	57.7%	55.9%	57.0%	58.8%	59.6%
EPCOR Utilities	61.0%	63.2%	65.7%	61.1%	60.7%	62.3%	64.6%
Great Lakes Power	47.1%	43.7%	42.3%	42.2%	39.5%	37.8%	40.3%
Nova Scotia Power	58.9%	59.1%	59.0%	59.9%	62.2%	62.8%	63.9%
Ontario Power Generation (1)	38.3%	37.1%	38.6%	38.7%	71.8%	75.0%	75.9%
TransAlta Utilities	54.7%	52.3%	60.3%	54.4%	50.8%	52.4%	50.8%
Group Average	52.9%	52.5%	55.1%	53.0%	57.6%	58.3%	59.1%
Transmission & Distribution							
Altalink (2)	59.9%	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	55.0%	56.3%	56.7%	NA	NA	NA	NA
Enersource Corporation	62.3%	61.4%	59.9%	0.0%	0.0%	0.0%	0.0%
ENMAX Corporation	16.5%	19.1%	60.9%	30.5%	33.4%	38.1%	32.4%
Hydro One (1)	57.1%	56.1%	53.5%	54.6%	NA	NA	NA
Hydro Ottawa	55.4%	56.6%	57.3%	2.6%	2.9%	0.9%	n/a
Newfoundland Power	54.8%	56.2%	54.0%	55.0%	55.5%	53.7%	53.1%
Toronto Hydro	65.4%	63.0%	63.6%	63.1%	4.4%	5.0%	4.1%
Veridian Corporation	57.8%	54.1%	52.2%	52.4%	7.7%	9.8%	n/a
Group Average	53.8%	52.9%	57.3%	36.9%	17.3%	17.9%	22.4%
Industry Average	60.3%	59.7%	62.0%	54.6%	50.5%	50.6%	52.5%
Holding Companies (consolidated)							
Canadian Utilities (3)	56.2%	57.3%	59.3%	59.0%	61.1%	61.5%	61.9%
Emera Inc. (4)	62.3%	62.6%	59.6%	61.0%	62.3%	62.8%	63.9%
Fortis Inc. (5)	60.6%	63.8%	62.4%	61.7%	57.9%	58.4%	55.4%
TransAlta Corp. (6)	52.0%	54.8%	52.5%	49.3%	44.9%	54.4%	56.3%

n/a = not available, NA = not applicable, nmf = not meaningful.

* 12 months ended June 30, 2002.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Altalink began its operations in April 2002.

(3) Canadian Utilities owns CU Inc.

(4) Emera owns Nova Scotia Power.

(5) Fortis owns Newfoundland Power.

(6) TransAlta Corp. owns TransAlta Utilities.

- Government-owned and guaranteed utilities continue to be more highly leveraged, with some utilities having over 80% debt in the capital structure
- Over the last few years, strong free cash flow has available to pay down debt. The improvement in free cash flow has resulted from the fact that:
  - Most utilities have not completed a major capital expansion project (except for Hydro-Québec), and
  - The improved fiscal performance of most governments over the last few years, which has reduced the need to have the utilities pay out large dividends
- However, increasing pressure once again on provincial budgets is resulting in increasing dividends, which will likely cause leverage to rise
- Investor-owned and non-government guaranteed utilities have much lower leverage, with capital structures typically in line with those deemed by the regulators for the regulated utilities:
  - Annual fluctuations in capital structures tend to be due to working capital requirements related to the distribution and transmission businesses or major capital projects and/or acquisitions

Table 9 (b): Average Coupon on Long-Term Debt							
Companies	As at						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	6.80%	7.80%	8.10%	7.70%	8.50%	8.50%
Hydro-Québec	n/a	8.05%	8.82%	8.71%	8.80%	8.91%	9.13%
Manitoba Hydro	n/a	8.17%	8.31%	8.38%	8.56%	8.79%	8.74%
NB Power	n/a	8.06%	8.39%	8.88%	9.07%	9.06%	9.07%
Newfoundland and Labrador Hydro	n/a	8.07%	8.40%	8.38%	8.73%	9.51%	10.10%
Saskatchewan Power	n/a	8.66%	8.95%	9.11%	9.20%	9.34%	9.47%
Churchill Falls	n/a	7.70%	7.71%	7.71%	7.71%	7.70%	7.70%
Group Average	n/a	7.93%	8.34%	8.47%	8.54%	8.83%	8.96%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	8.15%	8.15%	7.96%	8.18%	8.85%	8.76%	9.26%
CU Inc.	8.41%	8.41%	8.96%	9.20%	9.70%	9.72%	10.02%
EPCOR Utilities	n/a	9.14%	9.14%	9.59%	10.27%	10.29%	10.26%
Great Lakes Power	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Nova Scotia Power	n/a	7.59%	7.59%	7.58%	7.99%	8.03%	8.15%
Ontario Power Generation (1)	5.79%	5.79%	5.93%	5.93%	9.30%	9.30%	9.50%
TransAlta Utilities	7.25%	7.25%	7.21%	7.78%	8.16%	8.78%	9.32%
Group Average	7.40%	7.72%	7.80%	8.04%	9.05%	9.15%	9.42%
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	n/a	8.66%	n/a	NA	NA	NA	NA
Enersource Corporation	6.29%	6.29%	6.06%	NA	NA	NA	NA
ENMAX Corporation	7.57%	7.69%	7.77%	9.04%	9.08%	9.34%	10.11%
Hydro One (1)	7.82%	8.05%	8.13%	7.70%	NA	NA	NA
Hydro Ottawa (3)	6.90%	0.00%	0.00%	nmf	nmf	nmf	nmf
Newfoundland Power	na	9.56%	9.66%	9.66%	9.66%	10.26%	10.26%
Toronto Hydro	6.80%	4.27%	6.80%	6.80%	7.48%	7.57%	NA
Veridian Corporation	7.60%	7.60%	7.60%	NA	NA	NA	NA
Group Average	7.16%	6.52%	6.57%	8.30%	8.74%	9.06%	10.19%
Industry Average	7.28%	7.39%	7.57%	8.27%	8.77%	9.01%	9.52%
Holding Companies (consolidated)							
Canadian Utilities (4)	8.09%	8.06%	8.76%	8.92%	9.28%	9.66%	9.97%
Emera Inc. (5)	n/a	7.51%	7.59%	7.58%	7.99%	8.03%	8.15%
Fortis Inc. (6)	8.60%	8.90%	8.69%	9.11%	n/a	n/a	n/a
TransAlta Corp. (7)	6.95%	6.47%	7.12%	7.00%	7.90%	n/a	n/a

n/a = not available, NA = not applicable, nmf = not meaningful.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Altalink began its operations in April 2002.

(3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc.

(5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power.

(7) TransAlta Corp. owns TransAlta Utilities.

- The average coupon rate on long-term debt continues to fall as high coupon debt is paid down and refinanced at current low interest rates
- Most expansion programs for Canadian electric utilities occurred throughout the 1970s and 1980s when interest rates were high and, as a result, utilities locked in at high coupon rates
  - Newfoundland Power and EPCOR, in particular, continue to face high average coupon rates on long-term debt
- It is expected that utilities' average coupon rates will continue to decline over time given the current low interest rate environment
- Distribution companies in Ontario that were re-capitalized in 2000 and issued debt and/or promissory notes to their shareholders, have lower coupon rates due to the low interest rate environment at the time of re-capitalization
- Ontario Power Generation's low coupon rate is somewhat misleading as the coupon rate relates to its obligations on debt issued by the Province
  - Ontario Power Generation has not yet accessed the public term debt markets

Table 10 (a): EBIT Interest Coverage (times)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	1.49	1.54	2.40	1.91	1.64	1.65	1.47
Hydro-Québec	1.69	1.36	1.34	1.29	1.22	1.26	1.16
Manitoba Hydro*	1.31	1.39	1.53	1.31	1.19	1.22	1.21
NB Power	n/a	1.20	1.10	1.10	1.11	0.91	0.79
Newfoundland and Labrador Hydro	n/a	1.39	1.17	1.51	1.45	1.24	1.17
Saskatchewan Power*	1.59	1.39	1.85	1.71	1.79	1.70	1.69
Churchill Falls	n/a	1.60	1.73	1.75	1.68	1.53	1.46
Group Average	1.52	1.41	1.59	1.51	1.44	1.36	1.28
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	2.34	2.41	2.19	2.20	2.22	2.70	2.72
CU Inc.**	2.79	2.64	2.77	3.12	3.34	3.31	3.22
EPCOR Utilities**	2.83	3.29	1.98	1.84	1.93	1.82	1.81
Great Lakes Power	2.80	2.23	2.10	2.23	2.13	2.34	2.21
Nova Scotia Power	2.18	2.32	2.29	2.28	2.08	2.07	1.89
Ontario Power Generation (1)	1.37	2.13	6.41	4.88	1.46	1.50	1.64
TransAlta Utilities	4.89	6.12	2.00	2.63	3.35	3.19	4.02
Group Average	2.74	3.02	2.82	2.74	2.36	2.42	2.50
Transmission & Distribution							
Altalink (2)	2.01	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	3.05	1.97	1.87	NA	NA	NA	NA
Enersource Corporation	0.97	1.12	1.51	nmf	nmf	nmf	nmf
ENMAX Corporation	12.36	10.53	2.62	4.15	5.15	4.59	2.40
Hydro One (1)	2.50	2.65	2.50	2.45	NA	NA	NA
Hydro Ottawa (3)	2.10	nmf	nmf	3.10	5.20	4.47	n/a
Newfoundland Power	2.75	2.70	2.57	2.49	2.43	2.84	2.77
Toronto Hydro	1.19	1.57	0.82	6.04	8.22	7.81	14.68
Veridian Corporation	0.85	0.42	0.18	(0.70)	2.57	2.30	n/a
Group Average	3.09	2.99	1.72	2.92	4.71	4.40	6.62
Industry Average	2.45	2.47	2.04	2.39	2.84	2.73	3.47
Holding Companies (consolidated)							
Canadian Utilities** (4)	2.99	2.92	3.00	3.08	3.13	3.12	3.05
Emera Inc.** (5)	1.94	2.19	2.19	2.10	2.08	2.07	1.89
Fortis Inc.** (6)	2.46	2.34	2.07	2.36	2.17	2.63	2.76
TransAlta Corp. (7)	1.89	2.30	2.79	2.93	3.58	2.81	3.19

n/a = not available, NA = not applicable, nmf = not meaningful.

* 12 months ended June 30, 2002. ** Includes non-electricity operations.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Six months ended October 2002. Operations started April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- EBIT coverage for government-owned and guaranteed utilities deteriorated markedly in 2001 but appears to have rebounded somewhat in 2002
  - Deterioration in 2001 largely due to sluggish earnings
  - Coverage generally weak due to high debt levels
- For investor-owned or non-government guaranteed utilities, EBIT coverage was mixed in 2001 and 2002:
  - Alberta-based utilities generally experienced improvements in 2001 due to the opening of the competitive market and the high electricity prices
  - The sharp improvement in TransAlta Utilities EBIT coverage is due to an intercorporate transaction in 2001 consisting of the issuance of preferred securities to the parent, with the proceeds used to purchase intercompany preferred shares (dividends from these shares included in EBIT)
  - Ontario Power Generation's EBIT coverage fell sharply due to the significant amount of spending being undertaken on the Pickering A refurbishment, with most of the spending on this project being expensed rather than capitalized
- EBIT interest coverage for distribution companies in Ontario have been especially weak due to the phasing in of the rate increases necessary to achieve a market-based rate of return

Table 10 (b): Fixed-Charges Coverage (times)

Integrated Gov't. Owned & Guaranteed	12 months ended Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	1.49	1.54	2.40	1.91	1.64	1.65	1.47
Hydro-Québec	1.69	1.36	1.34	1.29	1.22	1.26	1.16
Manitoba Hydro*	1.31	1.39	1.53	1.31	1.19	1.22	1.21
NB Power	n/a	1.20	1.10	1.10	1.11	0.91	0.79
Newfoundland and Labrador Hydro	n/a	1.39	1.17	1.51	1.45	1.24	1.17
Saskatchewan Power*	1.59	1.39	1.85	1.71	1.79	1.70	1.69
Churchill Falls	n/a	1.60	1.73	1.75	1.68	1.53	1.46
Group Average	1.52	1.41	1.59	1.51	1.44	1.36	1.28
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	2.34	2.41	2.19	2.20	2.22	2.70	2.71
CU Inc.**	2.56	2.31	2.40	2.56	2.55	2.45	2.28
EPCOR Utilities**	2.67	3.12	1.98	1.84	1.93	1.82	1.81
Great Lakes Power	2.80	2.23	2.10	2.23	2.13	2.34	2.21
Nova Scotia Power	1.87	1.94	1.97	1.93	1.78	1.82	1.62
Ontario Power Generation (1)	1.37	2.13	6.41	4.88	1.46	1.50	1.64
TransAlta Utilities	2.24	3.02	1.58	1.92	2.46	2.49	2.99
Group Average	2.26	2.45	2.66	2.51	2.08	2.16	2.18
Transmission & Distribution							
Altalink (2)	2.01	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	3.05	1.97	1.87	NA	NA	NA	NA
Enersource Corporation	0.97	1.12	1.51	nmf	nmf	nmf	nmf
ENMAX Corporation	12.36	10.53	2.62	4.15	5.15	4.59	2.40
Hydro One (1)	2.31	2.45	2.30	2.32	NA	NA	NA
Hydro Ottawa (3)	2.10	nmf	nmf	3.10	5.20	4.47	n/a
Newfoundland Power	2.64	2.60	2.47	2.39	2.33	2.72	2.65
Toronto Hydro	1.19	1.57	0.82	6.04	8.22	7.81	14.68
Veridian Corporation	0.85	0.42	0.18	(0.70)	2.57	2.30	n/a
Group Average	3.05	2.95	1.68	2.88	4.69	4.38	6.58
Industry Average	2.28	2.27	1.98	2.30	2.74	2.63	3.35
Holding Companies (consolidated)							
Canadian Utilities** (4)	2.60	2.56	2.60	2.54	2.44	2.36	2.23
Emera Inc.** (5)	1.75	1.86	1.89	1.78	1.77	1.82	1.62
Fortis Inc.** (6)	2.29	2.16	1.89	2.11	1.93	2.07	2.06
TransAlta Corp. (7)	1.63	1.91	2.11	2.06	2.70	2.38	2.56

n/a = not available, NA = not applicable, nmf = not meaningful.

* 12 months ended June 30, 2002. ** Includes non-electricity operations.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Six months ended October 2002. Operations started April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- For government-owned and guaranteed utilities, the EBIT interest and fixed-charges coverage ratios are the same because they have no preferred shares
- Most government-owned transmission/distribution companies also do not have preferred shares – Hydro One is the exception
- For those companies having preferred shares, the fixed-charges coverage ratios are lower than EBIT interest coverage ratios
- Of particular note is TransAlta Utilities, which has a much lower fixed-charges coverage relative to EBIT coverage due to an intercorporate transaction in 2001 consisting of the issuance of preferred securities to the parent, with the proceeds used to purchase inter-company preferred shares (the dividends paid on the preferred securities included in fixed-charges coverage but not in EBIT interest coverage)
- Fixed-charges coverage ratios generally track EBIT interest coverage ratios
- It is expected that there will be an increasing divergence between fixed-charges coverage and EBIT interest coverage as more companies choose to use hybrid securities, deeply subordinated debt, and preferred shares with heavy equity characteristics as a source of financing

Table 11: Cash Flow/Adjusted Total Debt (times)							
Companies	12 months ended						
Integrated Govt Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	0.09	0.10	0.15	0.13	0.10	0.11	0.09
Hydro-Québec	0.09	0.08	0.08	0.07	0.06	0.06	0.05
Manitoba Hydro*	0.07	0.07	0.08	0.06	0.06	0.06	0.06
NB Power	n/a	0.08	0.07	0.08	0.08	0.05	0.04
Newfoundland and Labrador Hydro	n/a	0.03	0.06	0.11	0.09	0.06	0.04
Saskatchewan Power*	0.15	0.13	0.18	0.17	0.18	0.18	0.17
Churchill Falls	n/a	0.14	0.14	0.14	0.12	0.10	0.09
Group Average	0.10	0.09	0.11	0.11	0.10	0.09	0.08
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	0.14	0.12	0.10	0.11	0.09	0.12	0.14
CU Inc.**	0.18	0.18	0.18	0.20	0.19	0.18	0.18
EPCOR Utilities**	0.20	0.20	0.14	0.15	0.17	0.17	0.15
Great Lakes Power	0.12	0.10	0.11	0.12	0.13	0.14	0.13
Nova Scotia Power	0.12	0.13	0.15	0.14	0.13	0.13	0.11
Ontario Power Generation (1)	0.45	0.51	0.51	0.49	0.09	0.09	0.11
TransAlta Utilities	0.15	0.21	0.24	0.20	0.24	0.25	0.27
Group Average	0.19	0.21	0.20	0.20	0.15	0.15	0.16
Transmission & Distribution							
Altalink (2)	0.08	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.17	0.28	0.10	NA	NA	NA	NA
Enersource Corporation	0.08	0.10	0.11	nmf	nmf	nmf	nmf
ENMAX Corporation	1.55	2.05	0.14	0.51	0.59	0.45	0.30
Hydro One (1)	0.13	0.14	0.15	0.15	NA	NA	NA
Hydro Ottawa (3)	0.14	0.11	0.10	2.22	1.95	5.81	n/a
Newfoundland Power	0.18	0.20	0.19	0.16	0.16	0.18	0.19
Toronto Hydro	0.03	0.11	0.11	0.12	1.92	1.58	2.25
Veridian Corporation	n/a	0.13	0.09	0.08	1.13	0.85	n/a
Group Average	0.30	0.39	0.12	0.54	1.15	1.77	0.91
Industry Average	0.20	0.23	0.15	0.28	0.47	0.67	0.38
Holding Companies (consolidated)							
Canadian Utilities** (4)	0.18	0.20	0.19	0.20	0.18	0.18	0.18
Emera Inc.** (5)	0.11	0.10	0.14	0.14	0.14	0.13	0.11
Fortis Inc.** (6)	0.12	0.13	0.09	0.10	0.12	0.14	0.14
TransAlta Corp. (7)	0.17	0.19	0.21	0.18	0.23	0.22	0.20

n/a = not available, NA = not applicable, nmf = not meaningful.
* 12 months ended June 30, 2002. ** Includes non-electricity operations.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) Six months ended October 2002. Operations started April 2002. (3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- Given the high leverage for most government-owned and guaranteed utilities, cash flow/total adjusted debt tends to be weaker than for investor-owned or non-government guaranteed utilities:
  - In most cases, cash-flow/total-adjusted-debt fell in 2001 due to weaker earnings and remained stable in 2002
- For many investor-owned or non-government guaranteed utilities, cash-flow/total-adjusted-debt has improved or remained stable over the past two years:
  - Certain utilities, however, did experience declines, namely Ontario Power Generation, Nova Scotia Power, and TransAlta Utilities
  - The declines were due to weaker earnings
- Distribution and transmission companies continued to experience more volatility in this ratio due to the time lag in recovering deferral accounts
- Distribution companies operating in Ontario are likely to see some improvement in this ratio compared to the 12 months ended September 30, 2002 due to the recovery of certain deferral accounts since that time
  - However, this ratio will likely continue to be pressured over the next three years due to the distribution rate cap

Table 12: Cash Flow/Capital Expenditures (times)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	1.05	1.22	2.78	2.58	2.12	2.55	2.20
Hydro-Québec	1.53	1.77	0.90	1.25	1.03	1.11	1.00
Manitoba Hydro*	0.94	1.08	1.43	1.15	0.98	1.35	1.03
NB Power	n/a	1.67	1.81	2.49	3.68	2.61	1.72
Newfoundland and Labrador Hydro	n/a	0.39	1.33	1.97	3.11	2.30	1.61
Saskatchewan Power*	1.18	1.08	1.59	1.47	2.28	2.22	3.20
Churchill Falls	n/a	8.63	13.11	21.61	16.53	21.57	15.21
Group Average	1.18	2.26	3.28	4.65	4.25	4.82	3.71
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	0.47	0.60	0.61	0.56	0.45	0.82	0.85
CU Inc.**	1.28	1.43	1.52	1.93	1.50	1.41	1.78
EPCOR Utilities**	1.22	1.97	1.53	1.03	1.36	2.27	3.17
Great Lakes Power	4.20	9.04	3.76	7.71	6.03	6.33	4.48
Nova Scotia Power	1.68	1.89	1.98	2.07	1.70	2.23	2.28
Ontario Power Generation (1)	1.20	1.56	2.36	2.06	1.43	1.86	2.23
TransAlta Utilities	1.66	1.43	1.89	1.45	2.09	1.96	1.92
Group Average	1.67	2.56	1.95	2.40	2.08	2.41	2.39
Transmission & Distribution							
Altalink (2)	1.10	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.70	1.19	0.78	NA	NA	NA	NA
Enersource Corporation	0.73	0.85	1.12	1.77	1.48	1.02	1.28
ENMAX Corporation	2.06	3.81	1.09	1.26	2.93	3.23	1.58
Hydro One (1)	1.11	1.25	1.53	1.34	NA	NA	NA
Hydro Ottawa (3)	0.79	0.68	0.83	1.21	1.01	1.39	n/a
Newfoundland Power	1.00	1.03	1.36	1.19	1.09	1.73	1.84
Toronto Hydro	0.26	0.77	0.63	0.77	1.10	0.91	0.98
Veridian Corporation	n/a	0.71	0.85	0.62	1.39	0.91	n/a
Group Average	0.97	1.29	1.02	1.17	1.50	1.53	1.42
Industry Average	1.27	2.04	2.08	2.74	2.61	2.92	2.51
Holding Companies (consolidated)							
Canadian Utilities** (4)	0.92	0.87	1.21	1.51	1.14	1.27	1.73
Emera Inc.** (5)	1.75	1.24	1.88	2.16	1.78	2.23	2.29
Fortis Inc.** (6)	0.65	0.80	0.49	1.07	1.04	1.47	1.24
TransAlta Corp. (7)	0.46	0.48	0.73	0.69	1.48	1.58	1.44

n/a = not available, NA = not applicable, nmf = not meaningful.

* 12 months ended June 30, 2002 ** Includes non-electricity operations.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Six months ended October 2002. Operations started April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- Most utilities continue to experience year-over-year volatility in their cash flow/capital expenditures ratio
- For most generation companies and integrated utilities, cash flow generation has generally been sufficient to cover capital expenditures:
  - One notable exception has been Aquila Networks Canada (BC)
  - Newfoundland and Labrador Hydro also experienced a sharp deterioration in 2001 due to a combination of much weaker cash flow and much higher capital expenditures
- Distribution and transmission companies, particularly those in Ontario, have generally recorded much weaker cash flow/capital expenditures ratios than the integrated utilities:
  - Largely a result of weak earnings and, consequently, weak cash flows due to the regulatory environment in Ontario
- The cash flow/capital expenditures ratio for certain utilities will likely be pressured over the near term due to higher capital expenditure programs, namely Newfoundland and Labrador Hydro, Manitoba Hydro, Hydro-Québec, Hydro One, Canadian Utilities, and TransAlta Corporation

Table 13: Common Dividend Payout Ratio							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	46.8%	129.1%	43.3%	62.9%	80.1%	83.2%	77.9%
Hydro-Québec	30.9%	50.0%	50.0%	50.0%	41.1%	45.4%	0.0%
Manitoba Hydro*	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
N. Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Newfoundland and Labrador Hydro	n/a	99.8%	200.3%	24.9%	24.1%	48.2%	44.6%
Saskatchewan Power*	n/a	89.3%	63.0%	36.2%	81.9%	66.8%	53.5%
Churchill Falls	n/a	56.3%	57.0%	71.7%	86.3%	99.6%	76.6%
Group Average	19.4%	60.6%	59.1%	35.1%	44.8%	49.0%	36.1%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	46.1%	40.7%	54.5%	56.6%	62.6%	54.2%	56.5%
CU Inc.**	109.2%	104.3%	73.8%	84.6%	53.0%	65.5%	46.9%
EPCOR Utilities**	50.1%	39.9%	47.2%	60.5%	55.3%	57.5%	55.6%
Great Lakes Power	44.2%	56.5%	66.3%	66.8%	73.8%	60.8%	63.8%
Nova Scotia Power	188.7%	153.4%	89.9%	70.0%	83.2%	75.4%	76.3%
Ontario Power Generation (1)	430.2%	246.7%	41.8%	35.5%	0.0%	0.0%	0.0%
TransAlta Utilities	275.4%	0.0%	774.2%	259.7%	143.8%	210.8%	100.0%
Group Average	163.4%	91.6%	164.0%	90.5%	67.4%	74.9%	57.0%
Transmission & Distribution							
Altalink (2)	56.0%	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.0%	0.0%	nmf	NA	NA	NA	NA
Enersource Corporation	0.0%	0.0%	432.0%	NA	NA	NA	NA
ENMAX Corporation	21.3%	17.0%	67.1%	76.2%	43.0%	48.6%	108.9%
Hydro One (1)	57.1%	67.4%	58.7%	38.6%	NA	NA	NA
Hydro Ottawa (3)	0.0%	0.0%	0.0%	NA	NA	NA	NA
Newfoundland Power	41.5%	61.6%	66.6%	40.5%	90.9%	84.0%	134.3%
Toronto Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Veridian Corporation	0.0%	0.0%	0.0%	NA	NA	NA	NA
Group Average	19.5%	18.3%	89.2%	38.8%	44.6%	44.2%	81.1%
Industry Average	67.5%	56.8%	104.1%	54.8%	52.3%	56.0%	58.1%
Holding Companies (consolidated)							
Canadian Utilities** (4)	40.5%	50.2%	50.1%	54.5%	54.6%	54.8%	55.2%
Emera Inc.** (5)	81.5%	70.9%	70.1%	71.9%	83.3%	75.4%	76.3%
Fortis Inc.** (6)	47.3%	55.3%	74.6%	81.4%	97.9%	74.8%	73.6%
TransAlta Corp. (7)	93.1%	102.8%	126.3%	174.7%	109.3%	86.1%	66.4%

n/a = not available, NA = not applicable, nmf = not meaningful.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.

(2) Six months ended October 2002. Operations started April 2002.

(3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc.

(5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power.

(7) TransAlta Corp. owns TransAlta Utilities.

- The dividend payout ratio for government-owned and guaranteed integrated utilities has become more volatile in recent years:
  - Exception to this has been Hydro-Québec, where the payout ratio has been set at 50% of net income
  - Increased volatility related to provincial governments' increased use of dividends to manage their fiscal performances
  - This has been particularly the case for Newfoundland and Labrador Hydro
- For investor-owned or non-government guaranteed generation/integrated utilities, dividend payout ratios have also become more volatile
  - Over the past two years, dividend payout ratios have been higher than normal due to asset sales, with proceeds from the asset sales often being paid out to shareholders in the form of dividends
  - For certain other companies, the dividend payouts are set at fixed amounts or are set to ensure the maintenance of a target capital structure
- The municipally owned distribution companies in Ontario have not yet begun to payout dividends on a regular basis due to the current regulatory environment
  - Once the regulatory environment improves and these companies are producing stronger cash flows, the dividend payout policies for most of these companies will be to pay out the dividend required to ensure the maintenance of the target regulated capital structure
- The other transmission and distribution companies' pay out either fixed dividends or the amount required to ensure the maintenance of a target regulated capital structure

Table 14: Profit Returned to Government (before extraordinary items)							
Companies*	12 months ended						
Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	111.5%	62.2%	79.7%	90.4%	91.8%	90.4%
Hydro-Québec	n/a	12.6%	14.5%	30.1%	29.9%	26.5%	59.4%
Manitoba Hydro**	57.3%	52.9%	37.6%	49.8%	54.6%	52.5%	53.1%
NB Power	n/a	55.6%	nmf	41.2%	143.7%	240.7%	139.4%
Newfoundland & Labrador Hydro	n/a	99.8%	176.8%	35.3%	34.8%	58.7%	59.7%
Saskatchewan Power**	57.8%	96.2%	73.9%	51.4%	125.5%	79.6%	53.9%
Churchill Falls	n/a	63.5%	63.0%	75.8%	88.4%	99.7%	80.2%
Group Average	57.6%	70.3%	71.3%	51.9%	81.0%	92.8%	76.6%

n/a = not available, NA = not applicable, nmf = not meaningful.

* This table not especially relevant for investor-owned companies or companies that are government owned but not guaranteed.

** 12 months ended June 30, 2002

Note: Companies that are government-owned but not guaranteed have been excluded from this table, as the only difference between them and the investor-owned companies in terms of amounts remitted to governments is the dividend payments. All government-owned but not guaranteed companies, and investor-owned companies pay provincial, municipal, and property taxes.

- For the government-owned and guaranteed utilities, the governments receive returns from their utilities in the form of debt guarantee fees, royalties, water rentals, capital tax levies, and dividends
- Profits returned to the government vary significantly across provinces
- Many provinces will likely look at increasing certain fees as a way to help manage their fiscal positions

Section C – Unit Revenues and Costs

Note: The following statistics are not strictly comparable from one company to the next given the changing strategic focuses of many of the companies. For example, EPCOR Utilities is involved not only in electricity generation, transmission, and distribution, but also in retail marketing and water distribution. CU Inc. is involved in electricity generation, transmission, and distribution, but is also involved in gas distribution. Hydro One, on the other hand, is involved solely in transmission and distribution, while Ontario Power Generation and TransAlta Utilities are involved solely in generation.

Table 15 (a): Operation & Maintenance Costs - cents/kWk sold

Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	1.35	1.62	0.99	0.95	0.86	0.89
Hydro-Québec	n/a	1.52	1.50	1.45	1.39	1.22	1.13
Manitoba Hydro	n/a	1.09	1.04	1.05	0.86	0.72	0.81
NB Power	n/a	1.71	1.66	1.81	1.38	1.47	1.74
Newfoundland and Labrador Hydro	n/a	1.54	1.62	1.54	1.54	1.28	1.37
Saskatchewan Power	n/a	1.89	1.90	1.91	1.58	1.45	1.35
Churchill Falls	n/a	0.12	0.10	0.08	0.07	0.09	0.09
Group Average	n/a	1.32	1.35	1.26	1.11	1.01	1.05
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	2.14	1.94	1.96	1.91	1.84	1.81	2.01
CU Inc.*	4.46	4.72	4.59	3.21	3.07	3.23	3.36
EPCOR Utilities^ *	na	1.89	2.78	2.13	1.80	1.93	1.83
Great Lakes Power	na	0.89	0.78	0.54	0.50	0.59	0.68
Nova Scotia Power	1.48	1.44	1.47	1.39	1.43	1.46	1.72
Ontario Power Generation^ (1)	2.15	2.10	1.74	1.79	1.78	1.73	1.56
TransAlta Utilities^	0.72	0.75	0.67	0.71	0.65	0.95	0.96
Group Average	2.19	1.96	2.00	1.67	1.58	1.67	1.73
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.40	0.38	0.42	NA	NA	NA	NA
Enersource Corporation Corporation	0.40	0.30	0.28	0.26	0.27	0.34	0.36
ENMAX Corporation	1.96	1.89	1.40	1.02	0.84	0.62	0.73
Hydro One (1)	0.49	0.49	0.52	0.52	0.45	0.38	0.37
Hydro Ottawa (3)	0.62	0.51	0.59	0.52	0.50	0.49	0.50
Newfoundland Power	1.05	1.06	1.07	1.15	1.19	1.21	1.23
Toronto Hydro	0.78	0.65	0.66	0.71	0.64	0.66	0.68
Veridian Corporation	0.62	0.60	0.64	0.69	NA	NA	NA
Group Average	0.79	0.73	0.70	0.70	0.65	0.62	0.64
Industry Average	1.49	1.34	1.35	1.21	1.11	1.10	1.14
Holding Companies (consolidated)							
Canadian Utilities* (4)	4.30	4.35	4.51	3.95	4.07	4.10	4.17
Emera Inc.* (5)	2.24	1.71	1.58	1.50	1.46	1.46	1.72
Fortis Inc.* (6)	2.41	2.11	1.71	1.55	2.04	2.33	2.21
TransAlta Corp.^ (7)	0.80	0.87	0.75	0.70	0.67	1.15	1.04

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
^Unit costs are presented in cents/kWh generated.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.
(2) Altalink began its operations in April 2002.
(3) Nine months ended September 2002.
(4) Includes non-electricity operations. Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

Note: the numbers above are not necessarily comparable, especially for those companies with non-electricity operations included in the operating and maintenance costs.

- Operating and maintenance costs tend to be highest for nuclear- and coal-based generation and lowest for hydro-based generation, especially Churchill Falls
- Most vertically integrated and pure generation companies have had relatively stable unit operating and maintenance costs
- Distribution companies tend to have low unit operating and maintenance costs due to the lack of generation
  - One exception is ENMAX, which has exhibited rising unit operating and maintenance costs, largely due to their participation in electricity activities beyond pure distribution/transmission

Table 15 (b): Fuel Costs - cents/kWh sold							
Companies*	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	0.47	0.90	0.12	0.15	0.03	0.02
Hydro-Québec	n/a	0.71	0.49	0.43	0.35	0.18	0.02
Manitoba Hydro	n/a	0.04	0.06	0.06	0.08	0.03	0.03
NB Power	n/a	2.24	2.36	1.45	1.51	1.81	1.62
Newfoundland and Labrador Hydro	n/a	0.85	0.74	0.63	0.51	0.74	0.72
Saskatchewan Power	n/a	2.66	2.11	1.22	1.14	1.03	0.93
Churchill Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Group Average	nmf	1.00	0.95	0.56	0.53	0.55	0.48
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CU Inc.	0.86	0.95	1.02	0.89	0.79	0.80	0.74
EPCOR Utilities^	n/a	0.77	3.19	1.68	1.40	1.18	0.98
Great Lakes Power	n/a	0.52	0.40	0.41	0.34	0.35	0.32
Nova Scotia Power	2.63	2.55	2.37	2.34	2.47	2.36	2.42
Ontario Power Generation^ (1)	1.13	1.04	0.93	0.85	0.29	0.55	0.48
TransAlta Utilities^	0.51	0.49	0.42	0.40	0.40	0.38	0.38
Group Average	1.03	0.90	1.19	0.94	0.81	0.80	0.76
Industry Average	nmf	0.95	1.07	0.75	0.67	0.67	0.62
Holding Companies (consolidated)							
Canadian Utilities (2)	1.46	1.74	1.67	1.41	1.24	1.21	1.05
Emera Inc. (3)	3.09	2.44	2.37	2.34	2.47	2.36	2.42
Fortis Inc. (4)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TransAlta Corp.^ (5)	1.72	2.92	1.61	0.54	0.49	0.95	0.76

n/a = not available, NA = not applicable, nmf = not meaningful.

* This table does not apply to transmission and distribution companies.' ^Unit costs are presented in cents/kWh generated.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro.

(2) Canadian Utilities owns CU Inc. (3) Emera inc. owns Nova Scotia Power.

(4) Fortis owns Newfoundland Power. (5) TransAlta Corp. owns TransAlta Utilities. Includes purchased power.

- Fuel costs are very low for the predominantly hydro-based generating companies (and non-existent for those utilities that are 100% hydro-based)
- In the past, utilities that were predominantly coal-based or nuclear-based also tended to have low fuel costs
  - However, in 2001, the cost of coal increased resulting in much higher unit fuel costs for companies with a large amount of coal generation, namely Saskatchewan Power and Nova Scotia Power
- Utilities that have significant gas-based or oil-based generation capacity (i.e., EPCOR Utilities and NB Power) tend to face higher and more volatile fuel costs:
  - Oil- and gas-based generation was hit especially hard in late 2000/early 2001 when prices spiked up
  - Given the recent increases in oil and gas prices more recently, utilities having substantial oil- and/or gas-based generation will see their fuel costs rise
- Given the growing importance of gas-based generation, the cost of generation and, thus, electricity prices will become increasingly more sensitive to movements in the price of gas
- DBRS sees substantial future upward price pressures in natural gas in the US$3 to US$4 range going forward, which will likely result in rising electricity prices over time
- In the future, natural gas liquids may become a source of energy, but the capital costs are high, and technology is still evolving

Table 15 (c): Income Taxes - cents/kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	1.01	1.13	1.28	1.25	1.43	1.35	1.43
Hydro-Québec	NA	NA	NA	NA	NA	NA	NA
Manitoba Hydro	NA	NA	NA	NA	NA	NA	NA
NB Power	NA	NA	NA	NA	NA	NA	NA
Newfoundland & Labrador Hydro	NA	NA	NA	NA	NA	NA	NA
Saskatchewan Power	NA	NA	NA	NA	NA	NA	NA
Churchill Falls	NA	NA	NA	NA	NA	NA	NA
Group Average	1.01	1.13	1.28	1.25	1.43	1.35	1.43
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	0.17	0.25	0.25	0.20	0.23	0.34	0.35
CU Inc.*	1.00	1.09	1.19	1.39	1.54	1.45	1.56
EPCOR Utilities^ *	n/a	0.46	(0.01)	(0.02)	NA	NA	NA
Great Lakes Power	(0.06)	(0.13)	(0.05)	(0.06)	0.00	0.20	0.23
Nova Scotia Power	0.14	0.13	0.14	0.13	0.14	0.15	0.12
Ontario Power Generation^	0.04	0.05	0.29	0.29	NA	NA	NA
TransAlta Utilities^	0.22	0.40	0.13	0.30	0.43	0.50	0.72
Group Average	0.25	0.32	0.28	0.32	0.47	0.53	0.60
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.13	0.11	0.12	NA	NA	NA	NA
Enersource Corporation	0.03	0.00	NA	NA	NA	NA	NA
ENMAX Corporation	0.44	0.45	NA	NA	NA	NA	NA
Hydro One	0.13	0.16	0.13	0.12	NA	NA	NA
Hydro Ottawa (3)	0.01	0.00	NA	NA	NA	NA	NA
Newfoundland Power	0.38	0.33	0.33	0.39	0.36	0.42	0.42
Toronto Hydro	0.03	0.00	NA	NA	NA	NA	NA
Veridian Corporation	0.01	(0.03)	NA	NA	NA	NA	NA
Group Average	0.14	0.13	0.19	0.25	0.36	0.42	0.42
Industry Average	0.47	0.53	0.58	0.61	0.75	0.77	0.82
Holding Companies (consolidated)							
Canadian Utilities* (4)	1.01	1.13	1.28	1.25	1.43	1.35	1.43
Emera Inc.* (5)	0.14	0.13	0.12	0.06	0.14	0.15	0.12
Fortis Inc.* (6)	0.48	0.43	0.27	0.43	0.52	0.66	0.63
TransAlta Corp.^ (7)	0.14	0.20	0.32	0.28	0.36	0.50	0.51

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
^Unit costs are presented in cents/kWh generated.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.
(2) Altalink began its operations in April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- With corporate income tax rates slowly coming down across the country, unit income taxes have generally been trending downwards
- Government-owned and guaranteed utilities do not pay income taxes, but all government-owned non-guaranteed utilities pay proxy provincial income taxes in order to ensure a level playing field with investor-owned utilities

Table 16 (a): Fixed Costs (excluding preferred dividends) - cents/kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	3.26	2.94	2.92	2.99	2.89	2.78
Hydro-Québec	n/a	4.13	4.06	2.29	4.59	4.10	3.92
Manitoba Hydro	n/a	3.27	2.79	2.93	2.69	2.41	2.50
NB Power	n/a	2.87	3.48	3.20	3.30	3.56	4.19
Newfoundland and Labrador Hydro	n/a	2.10	2.25	2.33	2.46	2.32	2.46
Saskatchewan Power	n/a	2.99	2.63	2.00	2.79	2.86	2.78
Churchill Falls	n/a	0.11	0.10	0.11	0.10	0.12	0.13
Group Average	n/a	2.68	2.61	2.25	2.70	2.61	2.68
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	3.35	3.45	3.43	3.32	3.34	3.15	3.42
CU Inc.*	3.23	3.24	3.32	3.23	3.05	2.98	3.11
EPCOR Utilities^*	n/a	1.40	2.75	2.81	2.68	3.32	3.28
Great Lakes Power	n/a	3.35	3.54	3.19	3.29	3.10	3.31
Nova Scotia Power	2.34	2.32	2.32	2.37	2.43	2.54	2.68
Ontario Power Generation^ (1)	1.10	1.03	0.94	1.00	3.81	3.91	3.97
TransAlta Utilities^	0.45	0.53	0.77	1.07	1.06	1.39	1.47
Group Average	2.09	2.19	2.44	2.43	2.81	2.91	3.03
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.46	0.53	0.48	NA	NA	NA	NA
Enersource Corporation	0.59	0.57	0.46	0.29	0.28	0.29	0.29
ENMAX Corporation	1.32	1.80	1.44	1.20	1.15	1.11	1.10
Hydro One (1)	0.43	0.44	0.42	0.45	NA	NA	NA
Hydro Ottawa (3)	0.46	0.27	0.31	0.31	0.30	0.29	0.28
Newfoundland Power	1.32	1.30	1.24	1.25	1.20	1.17	1.14
Toronto Hydro	0.72	0.66	0.61	0.45	0.42	0.41	0.38
Veridian Corporation	0.61	0.62	0.41	0.34	NA	NA	NA
Group Average	0.74	0.77	0.67	0.61	0.67	0.65	0.64
Industry Average	1.42	1.88	1.91	1.76	2.06	2.06	2.12
Holding Companies (consolidated)							
Canadian Utilities*(4)	3.33	3.54	3.62	3.37	3.63	3.55	3.68
Emera Inc.*(5)	2.91	2.43	2.50	2.58	2.62	2.69	2.78
Fortis Inc.*(6)	1.92	1.89	1.63	1.39	1.89	1.82	1.68
TransAlta Corp.^ (7)	0.89	0.82	0.89	0.90	0.85	1.39	1.46

n/a = not available, NA = not applicable, nmf = not meaningful. * Includes non-electricity operations.

^Unit costs are presented in cents/kWh generated.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.

(2) Altalink began its operations in April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- On average fixed costs, which consist primarily of depreciation, government levies (excluding income taxes) and interest costs, have typically remained in the range of 2.5¢-3.5¢/kWh for the past ten years for vertically integrated utilities
  - However, on a company-by-company basis, unit fixed costs have been somewhat more volatile, largely due to changes in electricity generated from one year to the next
- For government-owned and guaranteed utilities that have experienced a decrease in unit fixed costs, it has largely been due to lower interest costs as high coupon debt is refinanced at lower rates
  - For those experiencing rising unit fixed costs, it has been primarily due to rising depreciation costs as a result of acquisitions and/or higher capital expenditures
- For the investor-owned or non-government guaranteed utilities, Aquila Networks Canada (BC) and Great Lakes Power tend to have much higher unit fixed costs than the others
  - Aquila Networks Canada (BC) has high government levies, while Great Lakes Power has high net interest costs
- Unit fixed costs for transmission and distribution companies are generally much lower due to the lack of generation assets
  - In addition, the municipally owned distribution companies only recently began incurring interest costs

Table 16 (b): Net Interest Expense cents/net kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	1.22	1.12	1.14	1.25	1.19	1.25
Hydro-Québec	n/a	2.40	2.36	2.49	2.70	2.40	2.43
Manitoba Hydro	n/a	1.52	1.36	1.48	1.50	1.35	1.44
NB Power	n/a	1.35	1.43	1.90	1.64	1.96	2.32
Newfoundland and Labrador Hydro	n/a	1.42	1.48	1.48	1.60	1.58	1.71
Saskatchewan Power	n/a	1.10	0.94	1.00	1.06	1.12	1.29
Churchill Falls	n/a	0.04	0.04	0.04	0.06	0.06	0.06
Group Average	n/a	1.29	1.25	1.36	1.40	1.38	1.50
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	1.12	1.18	1.17	1.05	0.99	0.89	0.97
CU Inc.*	1.36	1.32	1.44	1.37	1.29	1.25	1.39
EPCOR Utilities^*	n/a	0.61	1.37	1.40	1.30	1.68	1.75
Great Lakes Power	n/a	2.34	2.42	2.24	2.37	2.29	2.54
Nova Scotia Power	1.00	1.02	1.04	1.07	1.13	1.24	1.38
Ontario Power Generation^ (1)	0.17	0.14	0.12	0.15	2.25	2.35	2.38
TransAlta Utilities^	(0.02)	0.06	0.30	0.37	0.37	0.48	0.49
Group Average	0.73	0.95	1.12	1.09	1.39	1.45	1.56
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.12	0.16	0.11	NA	NA	NA	NA
Enersource Corporation	0.22	0.20	0.09	(0.06)	(0.05)	(0.04)	(0.04)
ENMAX Corporation	0.10	0.23	0.11	0.14	0.09	0.12	0.11
Hydro One (1)	0.20	0.21	0.21	0.23	NA	NA	NA
Hydro Ottawa (3)	0.11	(0.04)	-	0.01	0.01	0.01	0.01
Newfoundland Power	0.56	0.57	0.58	0.59	0.57	0.56	0.54
Toronto Hydro	0.24	0.17	0.13	0.01	0.03	0.03	0.02
Veridian Corporation	0.23	0.20	0.04	(0.01)	NA	NA	NA
Group Average	0.22	0.21	0.16	0.13	0.13	0.14	0.13
Industry Average	0.47	0.58	0.64	0.61	0.76	0.80	0.84
Holding Companies (consolidated)							
Canadian Utilities*(4)	1.09	1.07	1.21	1.14	1.19	1.17	1.33
Emera Inc.*(5)	1.27	1.08	1.08	1.13	1.21	1.33	1.65
Fortis Inc.*(6)	1.00	0.96	0.83	0.69	0.96	0.91	0.86
TransAlta Corp.^ (7)	0.15	0.19	0.23	0.20	0.25	0.48	0.51

n/a = not available, NA = not applicable, nmf = not meaningful. * Includes non-electricity operations.

^Unit costs are presented in cents/kWh generated .

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.

(2) Altalink began its operations in April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- Net interest costs/kWh have generally been higher for government-owned and guaranteed integrated utilities than for investor-owned or non-government guaranteed integrated utilities
  - Largely due to higher debt levels for the government-owned and guaranteed utilities
  - One exception is Great Lakes Power, which has very high unit net interest costs
- TransAlta Utilities has exceptionally low net interest costs due to an intercorporate transaction in 2001 consisting of the issuance of preferred securities to the parent, with the proceeds used to purchase intercompany preferred shares (dividends from these shares netted off of interest costs)
- Companies having fewer lines of business tend to have lower unit net interest costs
- Municipally owned distribution companies, in particular, have low net interest costs primarily because they have only recently began incurring interest costs.
- Companies that have high coupon debt will see a decline in unit net interest costs as high coupon debt is refinanced with lower coupon debt

Table 16 (c): Preferred Dividends-cents/net kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
This table does not apply to government-owned and guaranteed companies.							
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	NA	NA	NA	NA	NA	NA	NA
CU Inc.	0.13	0.13	0.13	0.18	0.24	0.27	0.34
EPCOR Utilities^	n/a	0.02	NA	NA	NA	NA	NA
Great Lakes Power	NA	NA	NA	NA	NA	NA	NA
Nova Scotia Power	0.09	0.11	0.09	0.11	0.11	0.10	0.15
Ontario Power Generation (1)	NA	NA	NA	NA	NA	NA	NA
TransAlta Utilities^	0.17	0.14	0.04	0.08	0.08	0.07	0.09
Group Average	0.13	0.10	0.09	0.12	0.14	0.15	0.19
Transmission & Distribution							
Altalink (2)	NA	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	NA	NA	NA	NA	NA	NA	NA
Enersource Corporation	NA	NA	NA	NA	NA	NA	NA
ENMAX Corporation	NA	NA	NA	NA	NA	NA	NA
Hydro One (1)	0.01	0.01	0.01	0.01	NA	NA	NA
Hydro Ottawa (3)	NA	NA	NA	NA	NA	NA	NA
Newfoundland Power	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Toronto Hydro	NA	NA	NA	NA	NA	NA	NA
Veridian Corporation	NA	NA	NA	NA	NA	NA	NA
Group Average	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Holding Companies (consolidated)							
Canadian Utilities * (4)	0.12	0.12	0.12	0.16	0.22	0.25	0.31
Emera Inc. * (5)	NA	NA	NA	NA	NA	NA	NA
Fortis Inc. * (6)	0.04	0.05	0.05	0.05	0.07	0.14	0.17
TransAlta Corp.^ (7)	0.04	0.05	0.07	0.07	0.05	0.06	0.08

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
^Unit costs are presented in cents/kWh generated.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.
(2) Altalink began its operations in April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- The government-owned and non-guaranteed utilities are starting to increasing their use of preferred shares as an alternative source of funding given their lack of access to the equity markets
- Most investor-owned utilities have been reducing their use of preferred shares, unless the costs can be recovered through rates, as they tend to be a more expensive source of financing
- Hybrid debt, which is deeply subordinated and gets partial equity treatment, is becoming a more widely used alternative to preferred shares, as the interest expense is deductible for income tax purposes
- TransAlta Utilities recently (in 2001) increased its usage of preferred shares/securities through an inter-company transaction, but it was not done for financing purposes (issued preferred securities to the parent, with the proceeds used to purchase inter-company preferred shares)

Table 16 (d): Government Levies (exlcuding income taxes) -cents/kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	0.97	0.92	0.93	0.94	0.95	0.95
Hydro-Québec	n/a	0.55	0.50	0.60	0.66	0.59	0.56
Manitoba Hydro	n/a	0.86	0.58	0.60	0.46	0.42	0.42
NB Power	n/a	0.28	0.29	0.33	0.29	0.34	0.40
Newfoundland and Labrador Hydro	n/a	0.19	0.19	0.20	0.21	0.19	0.19
Saskatchewan Power	n/a	0.39	0.32	0.31	0.32	0.33	0.34
Churchill Falls	n/a	0.01	0.01	0.01	0.01	0.01	0.01
Group Average	n/a	0.46	0.40	0.43	0.41	0.40	0.41
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	1.59	1.61	1.56	1.56	1.58	1.44	1.65
CU Inc. *	0.84	1.16	0.96	1.08	0.98	1.03	1.01
EPCOR Utilities^ *	n/a	0.18	0.47	0.52	0.50	0.58	0.62
Great Lakes Power	n/a	0.36	0.52	0.49	0.44	0.36	0.36
Nova Scotia Power	0.19	0.19	0.17	0.15	0.12	0.11	0.06
Ontario Power Generation^ (1)	0.30	0.25	0.28	0.28	0.22	0.22	0.22
TransAlta Utilities^	0.05	0.05	0.07	0.12	0.12	0.15	0.16
Group Average	0.59	0.54	0.58	0.60	0.57	0.56	0.58
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.03	0.03	0.03	NA	NA	NA	NA
Enersource Corporation	n/a	na	na	na	na	na	na
ENMAX Corporation	0.81	1.20	0.92	0.66	0.66	0.64	0.65
Hydro One (1)	n/a	na	na	na	NA	NA	NA
Hydro Ottawa (3)	0.04	na	na	na	na	na	na
Newfoundland Power	NA	NA	NA	NA	NA	NA	NA
Toronto Hydro	0.02	0.04	0.05	0.04	0.04	0.04	0.04
Veridian Corporation	n/a	n/a	n/a	n/a	NA	NA	NA
Group Average	0.22	0.42	0.33	0.35	0.35	0.34	0.34
Industry Average	0.41	0.48	0.44	0.46	0.44	0.43	0.44
Holding Companies (consolidated)							
Canadian Utilities * (4)	0.59	0.81	0.71	0.57	0.80	0.84	0.82
Emera Inc.* (5)	0.19	0.18	0.17	0.15	0.12	0.11	0.06
Fortis Inc. * (6)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TransAlta Corp.^ (7)	0.05	0.04	0.06	0.09	0.09	0.12	0.13

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
^Unit costs are presented in cents/kWh generated.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.
(2) Altalink began its operations in April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- Government levies include debt guarantee fees, water taxes, property and other municipal taxes, and dividend payments (for government-owned and guaranteed utilities only)
- For government-owned and guaranteed utilities, the range is quite wide from as little as 0.01¢/kWh for Churchill Falls to almost 1.0¢/kWh for BC Hydro
  - The increase in government levies in 2001 was largely due to lower electricity generated
- The range is also quite wide for investor-owned or non-government guaranteed generation/integrated utilities, with Aquila Networks Canada (BC) having the highest unit government levies and TransAlta Utilities having the lowest
- Companies operating in B.C. have the highest government levies in Canada
- For many municipally owned distribution companies in Ontario, government levies reported are not comparable with those of other companies, as many do not separate out municipal and property taxes

Table 16 (e): Depreciation-cents/kWh Sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	0.95	0.82	0.78	0.74	0.71	0.67
Hydro-Québec	n/a	1.32	1.33	1.31	1.32	1.18	1.05
Manitoba Hydro	n/a	0.93	0.89	0.88	0.76	0.65	0.65
NB Power	n/a	1.16	1.21	1.22	1.03	1.13	1.38
Newfoundland and Labrador Hydro	n/a	0.55	0.62	0.65	0.60	0.51	0.50
Saskatchewan Power	n/a	1.25	1.18	1.03	1.03	1.17	1.11
Churchill Falls	n/a	0.05	0.05	0.05	0.04	0.05	0.06
Group Average	n/a	0.89	0.87	0.85	0.79	0.77	0.77
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	0.76	0.72	0.74	0.74	0.80	0.84	0.84
CU Inc. *	1.87	1.92	1.88	1.86	1.76	1.73	1.72
EPCOR Utilities^ *	n/a	0.60	1.06	0.99	0.91	1.10	0.91
Great Lakes Power	n/a	0.65	0.60	0.47	0.48	0.44	0.42
Nova Scotia Power	0.99	0.97	0.96	0.99	0.99	1.00	1.05
Ontario Power Generation^ (1)	0.67	0.67	0.56	0.58	1.24	1.25	1.28
TransAlta Utilities^	0.44	0.44	0.41	0.59	0.57	0.77	0.84
Group Average	0.94	0.85	0.89	0.89	0.96	1.02	1.01
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.31	0.34	0.34	NA	NA	NA	NA
Enersource Corporation	0.37	0.37	0.37	0.35	0.33	0.33	0.33
ENMAX Corporation	0.42	0.37	0.41	0.40	0.40	0.35	0.34
Hydro One (1)	0.23	0.23	0.21	0.21	NA	NA	NA
Hydro Ottawa (3)	0.32	0.32	0.31	0.29	0.29	0.28	0.27
Newfoundland Power	0.76	0.73	0.65	0.66	0.63	0.60	0.59
Toronto Hydro	0.47	0.46	0.44	0.42	0.40	0.38	0.37
Veridian Corporation	0.37	0.41	0.37	0.36	NA	NA	NA
Group Average	0.41	0.40	0.39	0.38	0.41	0.39	0.38
Industry Average	0.68	0.71	0.72	0.71	0.72	0.73	0.72
Holding Companies (consolidated)							
Canadian Utilities * (4)	1.66	1.67	1.70	1.67	1.64	1.55	1.54
Emera Inc. * (5)	1.31	1.04	1.10	1.14	1.11	1.06	0.87
Fortis Inc. * (6)	0.93	0.95	0.81	0.71	0.96	0.95	0.81
TransAlta Corp.^ (7)	0.51	0.47	0.51	0.56	0.50	0.76	0.80

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
^Unit costs are presented in cents/kWh generated.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.
(2) Altalink began its operations in April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- Unit depreciation costs have averaged just under 1.0¢ per kWh for the past five years
- Depreciation rates for thermal generation tend to be slightly higher than for hydro generation, since the economic life for thermal facilities is usually lower than for hydro facilities. In addition, many thermal plants are older and more heavily depreciated
- Unit depreciation costs will likely remain stable for most utilities, except those that have announced major expansion programs over the medium term (i.e., Hydro-Québec, TransAlta Corporation and Great Lakes Power). Hydro-Québec with its new hydro plants has the highest depreciation costs

Table 17: Purchased Power - cents/gross kWh purchased							
Companies	12 months ended						
Integrated Govt Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	13.08	16.29	4.18	3.76	3.26	3.41
Hydro Québec	n/a	4.33	3.38	1.27	1.06	0.85	0.86
Manitoba Hydro	n/a	6.30	3.60	1.79	1.97	3.21	3.43
NB Power	n/a	5.24	4.78	3.61	3.82	3.83	3.00
Newfoundland & Labrador Hydro	n/a	0.79	0.80	0.74	0.57	0.61	0.60
Saskatchewan Power	n/a	2.18	1.87	2.79	2.92	2.15	1.62
Churchill Falls	NA	NA	NA	NA	NA	NA	NA
Group Average	n/a	5.32	5.12	2.40	2.35	2.32	2.15
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	5.62	3.37	3.10	2.92	2.83	2.57	2.20
CU Inc.	13.33	55.07	6.94	3.99	3.53	4.11	3.11
EPCOR Utilities*	n/a	9.66	3.99	3.05	2.81	3.49	3.50
Great Lakes Power	n/a	2.70	2.99	2.66	2.71	3.12	2.98
Nova Scotia Power	9.35	7.73	7.18	6.08	6.74	6.32	6.76
Ontario Power Generation (1)	4.38	4.73	5.00	3.41	4.97	6.10	6.17
TransAlta Utilities	NA	NA	na	na	na	na	na
Group Average	8.17	13.88	4.87	3.69	3.93	4.28	4.12
Transmission & Distribution							
Altalink (2)	NA	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	NA	NA	4.54	NA	NA	NA	NA
Enersource Corporation	7.87	6.83	6.38	6.35	6.38	6.37	6.35
ENMAX Corporation	6.47	8.66	6.63	4.60	4.41	4.35	4.87
Hydro One	7.48	5.95	4.88	5.19	NA	NA	NA
Hydro Ottawa (3)	7.44	6.72	6.42	6.28	6.27	6.27	6.25
Newfoundland Power	4.32	4.34	4.37	4.28	4.31	4.29	4.34
Toronto Hydro	8.01	6.77	6.35	6.31	6.34	6.26	6.35
Veridian Corporation	6.45	6.86	6.57	6.50	NA	NA	NA
Group Average	6.86	6.59	5.77	5.64	5.54	5.51	5.63
Industry Average	7.52	8.60	5.25	3.91	3.94	4.04	3.97
Holding Companies (consolidated)							
Canadian Utilities (4)	13.33	55.07	6.94	3.99	3.53	4.11	3.11
Emera Inc. (5)	5.43	6.98	7.18	6.08	6.74	6.32	6.76
Fortis Inc. (6)	n/a	5.32	6.87	5.92	6.21	6.06	5.91
TransAlta Corp. (7)	n/a	n/a	n/a	n/a	n/a	n/a	n/a

n/a = not available, NA = not applicable, nmf = not meaningful.
*For EPCOR, calculated as purchased power/total kWh sold, including retail marketing sales.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.
(2) Altalink began its operations in April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

Note: These numbers can be somewhat misleading for companies that purchase only small amounts and/or purchase power at peak periods, and also misleading for the government-owned and guaranteed companies that purchase power for export/trading purposes.

- The cost of purchased power generally increased in 2001 and 2002
  - High electricity prices were recorded in Alberta during the first six months of 2001
  - Electricity prices began rising in Ontario during the summer of 2002, but were frozen at 4.3¢/kWh in November 2002 by the provincial government
- High electricity prices across much of North America in 2001 also impacted many of the government-owned and guaranteed utilities that export/trade power
- Power purchases are generally made for three reasons:
  - To meet demand requirements (i.e., for distribution and retail marketing operations);
  - To meet contract requirements if self-generated electricity is not sufficient; and
  - For trading purposes

Table 18: Gross Electricity Revenues-cents/kWh sold

Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	9.11	10.87	4.91	4.65	4.42	4.36
Hydro-Québec	n/a	5.60	5.35	4.95	4.96	4.88	4.68
Manitoba Hydro	n/a	4.70	4.38	4.17	3.88	3.52	3.69
NB Power	n/a	6.71	6.69	6.14	5.71	5.99	5.99
Newfoundland & Labrador Hydro	n/a	3.88	3.68	3.96	3.98	4.30	4.35
Saskatchewan Power	n/a	6.66	6.33	5.90	5.81	5.78	5.78
Churchill Falls	n/a	0.29	0.28	0.27	0.25	0.26	0.28
Group Average	n/a	5.28	5.37	4.33	4.18	4.16	4.16
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	5.42	5.25	4.96	4.72	4.71	4.67	4.53
CU Inc. *	13.00	15.45	7.64	7.01	6.63	6.59	6.73
EPCOR Utilities^	n/a	4.96	9.13	6.79	6.12	6.51	6.40
Great Lakes Power	n/a	6.43	5.92	5.03	5.27	5.19	5.12
Nova Scotia Power	7.62	7.64	7.63	7.62	7.68	7.79	7.99
Ontario Power Generation (1)	4.69	4.17	4.12	4.08	6.24	6.16	6.23
TransAlta Utilities	2.53	2.98	2.02	2.80	3.08	3.96	4.13
Group Average	6.65	6.70	5.92	5.44	5.68	5.84	5.88
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	1.71	1.68	5.45	NA	NA	NA	NA
Enersource Corporation	8.75	7.63	7.11	7.02	7.00	6.91	6.94
ENMAX Corporation	11.09	14.31	9.18	6.68	6.59	6.48	6.53
Hydro One (1)	10.63	10.13	9.68	9.91	NA	NA	NA
Hydro Ottawa (3)	8.67	7.36	7.10	6.97	6.94	6.94	6.95
Newfoundland Power	7.70	7.70	7.59	7.55	7.50	7.68	7.64
Toronto Hydro	9.46	8.02	7.47	7.41	7.50	7.42	7.56
Veridian Corporation	7.57	7.86	7.46	7.38	NA	NA	NA
Group Average	8.20	8.09	7.63	7.56	7.10	7.09	7.12
Industry Average	7.42	6.69	6.31	5.77	5.65	5.70	5.72
Holding Companies (consolidated)							
Canadian Utilities * (4)	9.20	10.80	10.00	10.20	10.80	10.80	n/a
Emera Inc. (5)	10.04	8.04	7.63	7.62	7.68	7.79	7.99
Fortis Inc. * (6)	8.83	8.56	8.12	7.20	9.85	10.11	9.76
TransAlta Corp. (7)	3.78	5.15	3.94	2.73	2.79	4.55	4.51

n/a = not available, NA = not applicable, nmf = not meaningful. * Includes non-electricity operations.

^Calculated as net electricity revenues, incl. retail margins/self-generated kWh sold.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.

(2) Altalink began its operations in April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities. Includes trading margins.

Note: Unit revenues are not strictly comparable across companies given the different business profiles.

- Unit electricity revenues generally increased in 2001 for the government-owned and guaranteed utilities due to a combination of:
  - A further increase in electricity exports and the higher electricity prices in those markets (British Columbia, Manitoba, and Quebec); and
  - Higher rates to recover higher costs, primarily fuel costs (Alberta, Saskatchewan, and New Brunswick)
- Unit electricity revenues also increased for investor-owned or non-government guaranteed generation/integrated utilities
  - Due to higher electricity prices, particularly in Alberta, and higher costs incurred by certain regulated utilities that recover costs through rates
  - The exception is EPCOR Utilities. The decline is due to a change in 2001 in the method of calculating unit electricity revenues
- Unit electricity revenues were also generally higher in 2001 and 2002 for transmission and distribution companies in part due to increased electricity prices
  - For municipally owned companies in Ontario, the increase was also due to the phasing in of a market rate of return and the recovery in rates of new costs incurred as a result of the new operating environment

Table19 (a): Pre-Tax Cash Margin - cents/kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	1.14	1.82	1.40	1.22	1.41	1.28
Hydro-Québec	n/a	1.42	1.48	1.46	1.34	1.38	1.09
Manitoba Hydro	n/a	1.57	1.76	1.39	1.04	1.01	1.00
NB Power	n/a	1.33	1.23	1.13	1.10	0.78	0.67
Newfoundland & Labrador Hydro	n/a	0.83	0.63	1.06	1.13	0.94	0.80
Saskatchewan Power	n/a	1.36	1.75	1.69	1.88	2.02	2.04
Churchill Falls	n/a	0.12	0.13	0.14	0.12	0.12	0.13
Group Average	n/a	1.11	1.26	1.18	1.12	1.09	1.00
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	1.18	1.19	1.05	1.02	1.04	1.25	1.15
CU Inc. *	4.53	4.57	4.63	4.93	5.01	4.88	5.04
EPCOR Utilities *	n/a	2.00	2.39	2.15	2.11	2.48	2.33
Great Lakes Power	n/a	1.04	0.51	0.26	0.05	0.26	0.22
Nova Scotia Power	2.14	2.29	2.44	2.52	2.41	2.48	2.33
Ontario Power Generation (1)	0.88	0.76	1.16	1.14	1.86	1.39	1.70
TransAlta Utilities	1.30	1.67	0.71	1.20	1.46	1.82	2.31
Group Average	2.01	1.93	1.84	1.89	1.99	2.08	2.15
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.55	0.50	0.44	NA	NA	NA	NA
Enersource Corporation	0.47	0.51	0.51	0.63	0.55	0.52	0.38
ENMAX Corporation	2.56	3.53	1.00	1.02	1.33	1.10	0.66
Hydro One (1)	0.56	0.61	0.57	0.59	NA	NA	NA
Hydro Ottawa (3)	0.48	0.48	0.51	0.49	0.48	0.46	0.47
Newfoundland Power	1.76	1.73	1.62	1.58	1.49	1.67	1.60
Toronto Hydro	0.51	0.55	0.41	0.46	0.55	0.53	0.60
Veridian Corporation	0.36	0.28	0.30	0.28	NA	NA	NA
Group Average	0.91	1.02	0.67	0.72	0.88	0.86	0.74
Industry Average	1.46	1.36	1.26	1.26	1.33	1.34	1.30
Holding Companies (consolidated)							
Canadian Utilities * (4)	3.84	3.98	4.28	4.11	4.36	4.14	4.35
Emera Inc. * (5)	2.25	2.07	2.24	2.25	2.26	2.31	1.95
Fortis Inc. * (6)	1.45	1.27	0.81	0.93	1.22	1.39	1.34
TransAlta Corp. (7)	1.06	1.12	1.28	1.19	1.30	1.84	2.07

n/a = not available, NA = not applicable, nmf = not meaningful. * Includes non-electricity operations.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.

(2) Altalink began its operations in April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- Pre-tax cash margins were mixed in 2001 and 2002
- Generally speaking, pre-tax cash margins are not significantly different for government-owned and investor-owned generation/integrated utilities
- For those companies that experienced declines in 2001, the declines were largely related to higher unit fixed costs as a result of lower electricity generated
- The primary contributors to changes in pre-tax cash margins are changes in electricity generated and/or volume throughputs, and changes in wholesale electricity prices
  - Declining interest rates, increased operating efficiencies and changing margins on exports/trading/retail marketing are also contributors

Table19 (b): Net Margin (before extras., after prefs.) - cents/kWh sold							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed^	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	n/a	0.50	1.24	0.82	0.63	0.78	0.66
Hydro Québec	n/a	0.58	0.58	0.54	0.43	0.49	0.32
Manitoba Hydro	n/a	0.73	0.94	0.57	0.36	0.38	0.37
NB Power	n/a	0.20	(0.35)	0.37	(0.12)	(0.29)	(0.49)
Newfoundland & Labrador Hydro	n/a	0.48	0.21	0.61	0.67	0.46	0.31
Saskatchewan Power	n/a	0.17	0.63	1.07	0.58	0.69	0.94
Churchill Falls	n/a	0.07	0.08	0.09	0.08	0.07	0.07
Group Average	n/a	0.39	0.48	0.58	0.38	0.37	0.31
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	0.68	0.61	0.46	0.45	0.42	0.48	0.44
CU Inc. *	1.58	1.08	0.94	1.49	1.51	1.61	1.78
EPCOR Utilities *	n/a	0.92	1.49	1.27	1.23	1.42	1.42
Great Lakes Power	n/a	0.39	(0.08)	(0.21)	(0.43)	(0.18)	(0.19)
Nova Scotia Power	0.75	0.94	1.10	1.13	0.99	1.03	0.81
Ontario Power Generation (1)	0.27	0.16	0.35	0.32	0.68	0.18	0.42
TransAlta Utilities	0.48	0.70	0.13	0.24	0.39	0.50	0.68
Group Average	0.75	0.69	0.63	0.67	0.68	0.72	0.77
Transmission & Distribution							
Altalink (2)	n/a	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	0.11	0.05	(0.02)	NA	NA	NA	NA
Enersource Corporation	0.07	0.14	0.14	0.28	0.22	0.29	0.15
ENMAX Corporation	1.70	2.70	0.59	0.62	0.93	0.76	0.32
Hydro One (1)	0.19	0.22	0.23	0.26	NA	NA	NA
Hydro Ottawa (3)	0.16	0.01	(0.01)	0.03	0.03	0.04	0.05
Newfoundland Power	0.63	0.69	0.65	0.55	0.51	0.66	0.60
Toronto Hydro	0.01	0.09	(0.03)	0.04	0.15	0.15	0.23
Veridian Corporation	(0.02)	(0.10)	(0.07)	(0.08)	NA	NA	NA
Group Average	0.36	0.47	0.19	0.24	0.37	0.38	0.27
Industry Average	0.55	0.52	0.43	0.50	0.48	0.49	0.45
Holding Companies (consolidated)							
Canadian Utilities * (4)	1.62	1.63	1.62	1.45	1.50	1.46	1.42
Emera Inc. * (5)	0.94	1.04	1.14	1.12	1.15	1.25	1.08
Fortis Inc. * (6)	0.52	0.32	(0.00)	0.21	0.26	0.44	0.53
TransAlta Corp (7)	0.32	0.37	0.33	0.26	0.37	0.50	0.69

n/a = not available, NA = not applicable, nmf = not meaningful. * Includes non-electricity operations.

(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation.
Numbers prior to 1999 were Ontario Hydro. Transmission + distribution throughputs used as electricity sold for Hydro One.

(2) Altalink began its operations in April 2002. (3) Nine months ended September 2002.

(4) Canadian Utilities owns CU Inc. (5) Emera owns Nova Scotia Power.

(6) Fortis owns Newfoundland Power. (7) TransAlta Corp. owns TransAlta Utilities.

- Net margins differ from the previous table as they are calculated after depreciation and any other non-cash expense, income taxes and preferred dividends
- For government-owned and guaranteed utilities, the difference between pre-tax cash margin and net margin is limited given that they do not pay income taxes
- Net margins are affected by the same factors as pre-tax cash margins
  - However, net margin may move in opposite direction of pre-tax cash margin if a company has a significant amount of capitalized interest and/or a high level of preferred shares

Section D – Operating Efficiencies & Profitability

Table 20: Operating Margins							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	17.5%	12.7%	18.0%	32.3%	33.6%	40.1%	40.5%
Hydro Québec	34.3%	34.1%	37.4%	42.3%	43.6%	46.3%	47.9%
Manitoba Hydro	40.1%	41.6%	46.0%	43.4%	44.5%	48.2%	48.4%
NB Power	n/a	21.7%	20.7%	26.4%	28.0%	24.1%	22.8%
Newfoundland & Labrador Hydro	n/a	37.1%	33.3%	41.2%	45.6%	43.3%	42.5%
Saskatchewan Power	22.9%	18.7%	24.0%	27.5%	32.3%	33.6%	37.8%
Churchill Falls	n/a	37.0%	42.0%	47.3%	48.0%	45.6%	43.8%
Group Average	28.7%	29.0%	31.6%	37.2%	39.4%	40.2%	40.5%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	24.3%	26.1%	24.7%	23.8%	23.6%	26.6%	26.3%
CU Inc. *(4)	20.9%	14.8%	19.6%	26.2%	30.0%	28.6%	31.3%
EPCOR Utilities *	14.8%	13.3%	19.0%	23.5%	25.2%	27.0%	28.8%
Great Lakes Power	59.1%	58.5%	58.7%	62.5%	60.4%	63.5%	66.9%
Nova Scotia Power	28.4%	30.9%	31.1%	31.8%	31.6%	33.7%	35.0%
Ontario Power Generation (1)	4.4%	5.7%	17.0%	17.2%	42.5%	37.5%	42.2%
TransAlta Utilities	33.1%	43.2%	29.8%	34.7%	40.9%	38.8%	45.6%
Group Average	26.4%	27.5%	28.6%	31.4%	36.3%	36.5%	39.4%
Transmission & Distribution							
Altalink (2)	41.8%	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	32.2%	29.7%	21.1%	NA	NA	NA	NA
Enersource Corporation	21.9%	25.7%	19.9%	19.9%	13.2%	15.7%	9.0%
ENMAX Corporation	41.3%	49.5%	20.5%	26.7%	35.0%	35.5%	20.1%
Hydro One (1)	42.1%	45.1%	43.5%	45.6%	NA	NA	NA
Hydro Ottawa (3)	20.9%	-3.9%	-1.2%	4.6%	4.4%	6.2%	8.0%
Newfoundland Power	46.3%	46.8%	47.3%	45.5%	44.0%	47.2%	45.8%
Toronto Hydro	18.0%	18.3%	7.9%	4.3%	14.1%	14.0%	18.8%
Veridian Corporation	16.5%	6.9%	-2.2%	-8.0%	5.2%	8.6%	n/a
Group Average	31.2%	27.3%	19.6%	19.8%	19.3%	21.2%	25.4%
Industry Average	28.8%	27.9%	26.6%	29.5%	31.7%	32.6%	35.1%
Holding Companies (consolidated)							
Canadian Utilities *(4)	20.9%	16.4%	20.3%	24.9%	28.1%	27.3%	29.8%
Emera Inc. * (5)	23.0%	26.8%	28.0%	29.9%	31.1%	33.7%	35.0%
Fortis Inc. * (6)	24.7%	23.5%	19.0%	20.5%	19.3%	21.2%	21.9%
TransAlta Corp. (7)	18.4%	16.4%	25.6%	30.6%	37.5%	34.4%	39.4%

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) 6 months ended October 2002. Operations started April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- Operating margins are defined as operating income divided by total revenues
- This ratio can be misleading if a utility does a significant amount of exporting/trading/retail marketing, with these gross revenues recorded in total revenues
  - This is the case for BC Hydro, Hydro-Québec, Manitoba Hydro, and EPCOR Utilities
  - TransAlta Corporation records only net margins in their total revenues
- For the municipally owned distribution companies in Ontario, operating margins in 2001 were misleading due to the transition period to prepare for the competitive market
- Operating margins have generally been on a declining trend since the mid-1990s

Table 21: Net Margins (before extras., after prefs.)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	5.6%	4.1%	10.9%	15.7%	13.4%	17.2%	14.8%
Hydro Québec	13.8%	8.8%	9.4%	9.4%	7.7%	9.5%	6.8%
Manitoba Hydro	11.9%	14.3%	19.4%	12.6%	9.3%	10.6%	9.9%
NB Power	n/a	3.0%	-5.0%	5.8%	-2.1%	-4.6%	-8.0%
Newfoundland & Labrador Hydro	n/a	16.4%	11.5%	21.5%	22.9%	14.8%	10.0%
Saskatchewan Power	9.5%	2.6%	9.8%	17.8%	9.8%	11.8%	16.1%
Churchill Falls	n/a	23.6%	28.3%	31.4%	31.1%	25.0%	23.7%
Group Average	10.2%	10.4%	12.0%	16.3%	13.2%	12.0%	10.5%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	12.2%	11.3%	9.0%	9.2%	8.6%	10.0%	9.5%
CU Inc. *(4)	8.1%	5.5%	6.8%	9.1%	9.9%	9.6%	9.7%
EPCOR Utilities *	6.7%	7.8%	6.7%	6.1%	10.5%	11.7%	12.4%
Great Lakes Power	33.1%	30.7%	27.1%	33.9%	30.1%	32.3%	30.9%
Nova Scotia Power	10.2%	12.5%	12.7%	12.9%	11.3%	12.4%	12.1%
Ontario Power Generation (1)	1.0%	2.4%	8.2%	7.5%	10.5%	2.8%	6.4%
TransAlta Utilities	18.9%	23.6%	6.6%	8.5%	12.8%	12.5%	15.7%
Group Average	12.9%	13.4%	11.0%	12.5%	13.4%	13.0%	13.8%
Transmission & Distribution							
Altalink (2)	19.1%	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	9.8%	4.8%	-2.2%	NA	NA	NA	NA
Enersource Corporation	-3.5%	2.8%	8.5%	27.5%	20.7%	9.9%	15.1%
ENMAX Corporation	31.3%	39.5%	17.3%	21.9%	32.0%	30.5%	14.9%
Hydro One (1)	14.6%	16.2%	17.0%	18.7%	NA	NA	NA
Hydro Ottawa (3)	11.0%	1.6%	-1.2%	3.1%	3.5%	4.8%	6.4%
Newfoundland Power	18.0%	19.7%	19.1%	15.7%	15.0%	18.3%	16.8%
Toronto Hydro	1.2%	6.7%	-1.9%	5.4%	15.7%	14.9%	20.9%
Veridian Corporation	-3.6%	-9.0%	-6.3%	-6.8%	7.0%	7.0%	n/a
Group Average	10.9%	10.3%	6.3%	12.2%	15.7%	14.2%	25.4%
Industry Average	11.3%	11.4%	9.8%	13.7%	14.1%	13.1%	16.6%
Holding Companies (consolidated)							
Canadian Utilities *(4)	8.9%	6.8%	7.8%	9.1%	9.7%	9.4%	9.4%
Emera Inc. * (5)	8.3%	11.4%	11.6%	12.3%	11.1%	12.4%	12.1%
Fortis Inc. * (6)	9.7%	8.9%	6.9%	7.0%	6.3%	8.6%	9.2%
TransAlta Corp. (7)	8.4%	7.2%	8.3%	9.4%	13.2%	11.0%	15.2%

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) Six months ended October 2002. Operations started April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- Net margin is defined as net earnings (before extraordinary items, after preferred dividends) divided by total revenues
- Again, this ratio can be misleading if a utility does a significant amount of exporting/trading/retail marketing, with these gross revenues recorded in total revenues
- Net margins for government-owned and guaranteed utilities have been somewhat volatile in recent years
  - Net margins have been heavily dependent on the state of export markets and on operational performance
- For investor-owned or non-government guaranteed generation/integrated utilities, the results have varied as well
  - EPCOR Utilities' net margin remains relatively low, largely due to its recent participation in retail energy marketing
  - For regulated utilities, net margins are in the 10% to 12% range, which is reasonable given the business risk profile
- It is expected that net margins for the municipally owned distribution companies will stabilize over the next year, but will likely remain relatively low given the changes in the regulatory environment
- For the pure generation companies, the net margin provides a good indicator of the per cent drop in average electricity prices that a company can sustain and still break even, all else remaining the same

Table 22: Return on Average Common Equity (before extras., after prefs.)							
Companies	12 months ended						
Integrated Gov't. Owned & Guaranteed	Sept. 2002	2001	2000	1999	1998	1997	1996
BC Hydro	14.4%	15.6%	53.6%	38.6%	31.9%	36.0%	30.6%
Hydro Québec	12.5%	7.9%	7.6%	6.6%	5.1%	6.2%	4.3%
Manitoba Hydro	13.5%	17.9%	28.3%	20.5%	16.3%	21.6%	25.0%
NB Power	n/a	nmf	nmf	nmf	-13.9%	-18.2%	-23.6%
Newfoundland & Labrador Hydro	n/a	9.4%	5.8%	11.2%	12.3%	8.2%	5.7%
Saskatchewan Power	9.2%	2.6%	9.8%	16.9%	9.7%	10.9%	14.4%
Churchill Falls	n/a	6.3%	7.9%	8.6%	8.8%	6.6%	5.9%
Group Average	12.4%	10.0%	18.8%	17.1%	10.0%	10.2%	8.9%
Integrated/Investor-Owned/No Gov't. Guarantee							
Aquila Networks Canada (BC)	11.7%	11.7%	10.0%	10.5%	10.3%	12.5%	12.7%
CU Inc. *(4)	12.3%	11.4%	11.7%	12.3%	12.7%	13.1%	13.3%
EPCOR Utilities *	15.6%	21.3%	17.0%	14.2%	15.7%	16.1%	19.0%
Great Lakes Power	11.3%	9.3%	8.2%	8.1%	7.3%	9.2%	8.7%
Nova Scotia Power	8.9%	10.9%	10.9%	11.1%	9.5%	10.6%	10.6%
Ontario Power Generation (1)	1.2%	2.7%	8.8%	8.2%	-24.5%	-25.6%	16.1%
TransAlta Utilities	16.0%	20.1%	3.8%	5.4%	9.0%	11.1%	14.1%
Group Average	11.0%	12.5%	10.1%	10.0%	5.7%	6.7%	13.5%
Transmission & Distribution							
Altalink (2)	5.2%	NA	NA	NA	NA	NA	NA
Aquila Networks Canada (AB)	8.3%	4.2%	-0.7%	NA	NA	NA	NA
Enersource Corporation	-1.4%	1.0%	1.4%	3.0%	2.1%	1.0%	1.5%
ENMAX Corporation	17.7%	41.0%	13.4%	13.9%	22.0%	18.1%	8.0%
Hydro One (1)	8.6%	9.7%	9.4%	12.7%	NA	NA	NA
Hydro Ottawa (3)	4.1%	0.5%	-0.3%	0.5%	0.5%	0.7%	1.0%
Newfoundland Power	10.6%	12.1%	11.6%	9.9%	9.4%	12.4%	10.9%
Toronto Hydro	0.7%	4.1%	-1.1%	1.5%	2.9%	2.9%	4.4%
Veridian Corporation	-1.6%	-3.0%	-1.8%	-1.3%	1.0%	2.0%	n/a
Group Average	5.8%	8.7%	4.0%	5.7%	6.3%	6.2%	25.4%
Industry Average	9.7%	10.4%	11.0%	10.9%	7.4%	7.7%	15.9%
Holding Companies (consolidated)							
Canadian Utilities *(4)	14.3%	15.0%	15.4%	14.5%	14.7%	14.9%	14.9%
Emera Inc. * (5)	8.7%	10.6%	10.9%	10.8%	9.5%	10.6%	10.6%
Fortis Inc. * (6)	12.8%	13.0%	10.6%	10.3%	8.9%	13.3%	14.5%
TransAlta Corp. (7)	6.2%	7.3%	6.0%	4.2%	7.0%	10.4%	14.0%

n/a = not available, NA = not applicable, nmf = not meaningful.
* Includes non-electricity operations.
(1) In 1999, Ontario Hydro was reorganized into Hydro One and Ontario Power Generation. Numbers prior to 1999 were Ontario Hydro.
(2) Six months ended October 2002. Operations started April 2002.
(3) Nine months ended September 2002.
(4) Canadian Utilities owns CU Inc.
(5) Emera owns Nova Scotia Power.
(6) Fortis owns Newfoundland Power.
(7) TransAlta Corp. owns TransAlta Utilities.

- The generally smaller equity base of government-owned and guaranteed utilities relative to investor-owned or non-government guaranteed utilities tend to distort this ratio
- Investor-owned or non-government guaranteed generation/integrated utilities have continued to record favourable rates of return over the past two years
  - TransAlta Utilities and EPCOR Utilities were important beneficiaries of the start of new competitive environment in Alberta, including the implementation of the legislatively mandated Power Purchase Arrangements
  - Ontario Power Generation has recorded poor rates of return, largely due to the high expenses related to the Pickering A return-to-service project, as well as the delays in returning to service the Pickering A units
- Rates of return for the transmission and distribution companies are widely dispersed, especially for the municipally owned distribution companies
  - Rates of return for the municipally owned distribution companies have been weak as market rates of return were being phased in
  - They are expected to remain weak over the next three years due to the government-imposed rates caps

AltaLink, L.P.

Current Report: July 22, 2002

Geneviève Lavallée, CFA / Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
A (high)	Stable	New Rating	Corporate Rating*

*Highest rating applicable to the direct obligations of Altalink, L.P.

RATING HISTORY	Current	2001	2000	1999	1998
Corporate Rating	A (high)	NR	NR	NR	NR

RATING RATIONALE

DBRS is assigning a corporate rating of A (high) to Altalink, L.P. ("ALP" or "the Company"). The trend is Stable. The rating is supported by the following factors. (1) The Company is currently involved solely in the regulated electricity transmission business in Alberta and intends to continue to invest only in regulated transmission assets in Alberta. As ALP is expected to derive 100% of its net earnings and cash flows from this regulated business, its financial profile should remain relatively stable. Based on the 2001 approved settlement, the implied deemed capital structure is 35% equity, 10% preferred shares and 55% debt. The Company's current capital structure is 40% equity, 10% subordinated debt and 50% senior debt. Furthermore, the framework within which electricity transmission is governed in Alberta provides for increased stability to earnings and cash flows given that regulated transmission businesses face no volume risk and very limited counterparty risk. (2) ALP has one of the most favourable franchise areas in Canada, providing additional support to its financial profile and growth potential. ALP serves approximately 90% of the Alberta customer base. The economic fundamentals of Alberta are strong, and the economic growth outlook remains favourable. (3) Additional support is provided by the potential implementation of performance-based regulation (PBR) in the medium term. This would offer the Company the opportunity to register earnings growth beyond the current low regulated rates of return in Canada.

While the regulated nature of its asset base and the favourable franchise area within which it operates provide strong support to ALP's financial and business risk profile, there exist a number of challenges that limit the rating to an A (high). As is the case for virtually all regulated utilities in Canada, ALP faces regulatory risk and low regulated rates of return. Although regulatory decisions in Canada have rarely been as negative as those rendered by various regulators in the U.S., ALP faces the risk that the Alberta regulator could render a decision that would have a material negative impact on its earnings and cash flows. In addition, regulated utilities in Canada currently receive low approved rates of return compared to their peers in the U.S., limiting the strength of their key financial ratios. Over the medium term, ALP is expected to record free cash flow deficits due to the projected capital expenditures. While ALP's sole shareholder, AltaLink Investment L.P. ("AILP"), is expected to provide the equity and subordinated debt injections required to maintain ALP's regulated capital structure, it could be a challenge if AILP is unable to obtain the necessary financing.

RATING CONSIDERATIONS

Strengths:

- Involved solely in regulated activities
- No volume risk; limited counterparty risk
- Attractive Alberta-based business franchise
- Potential implementation of PBR framework in medium term offers opportunity for improved earnings growth

Challenges:

- Regulatory risk
- Low regulated rates of return/approved ROEs sensitive to interest rates
- Free cash flow deficits projected over medium term
- Financially weaker parent

FINANCIAL INFORMATION

	For the year ending April 30		For the year ending December 31*		
	2004P	2003P	2001E	2000	1999
Fixed-charges coverage (times)	1.74	2.01	2.44	2.42	2.38
% debt in capital structure (1)	62.2%	61.0%	n/a	53.8%	51.8%
Cash flow/total debt (times)	0.15	0.15	n/a	0.23	0.25
Cash flow/capital expenditures (times)	1.18	1.20	1.96	n/a	n/a
Net income (before extras.) ($ millions)	26.4	30.8	27.0	31.4	32.1
Operating cash flow ($ millions)	83.1	80.2	78.2	81.9	82.1
Operating margin	37.3%	37.9%	50.6%	49.5%	51.4%
Return on average equity	7.7%	9.1%	n/a	10.6%	10.8%

P: Company's projections.

* Figures for 1999, 2000, and 2001E relate to when TransAlta Utilities owned the assets.

THE COMPANY Altalink, L.P. ("ALP") was recently established to own and operate the regulated transmission assets in Alberta acquired from TransAlta Utilities. ALP intends to focus solely on regulated transmission activities in Alberta. AltaLink Investment L.P. ("AILP") is the holding company of Altalink, L.P. The sponsors of AILP include: Macquarie North America Ltd. (15%), Ontario Teachers' Pension Plan Board (25%), SNC-Lavalin Inc. (50%), and Trans-Elect Inc. (10%). AltaLink Management Ltd. is the general partner of ALP, and SNC-Lavalin and Trans-Elect are the general partners (50/50) of AltaLink Management Ltd.

Aquila Networks Canada (Alberta) Ltd.

Current Report: July 31, 2002
Previous Report: June 14, 2001

Geneviève Lavallée, CFA / Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Senior Unsecured Debt
R-1 (low)	Stable	Confirmed	Commercial Paper

RATING HISTORY

RATING HISTORY	Current	2001	2000	1999	1998	1997	1996
Senior Unsecured Debt	"A"	"A"	NR	NR	NR	NR	NR
Commercial Paper	R-1 (low)	R-1 (low)	NR	NR	NR	NR	NR

RATING UPDATE

Aquila Networks Canada (Alberta) Ltd. ("ANCA" or "the Company") reported favourable financial results in 2001, its first full year of operations. The Company's leverage and key financial ratios (cash flow/net debt and interest coverage) were in line with those expected for an "A"-rated, regulated utility, with per cent net debt in the capital structure at 56%, cash flow/net debt at 0.28 times, and fixed-charges coverage just under 2.0 times. Relative to the financial projections upon which the initial rating was based, the results for 2001 were better than expected.

The outlook for ANCA remains favourable, although it faces potential near-term challenges related to its parent, Aquila, Inc.'s ("Aquila"), credit and liquidity concerns. Aquila's current liquidity concerns could impact the level of financial support available to ANCA should the Company require it. However, DBRS does not believe that ANCA will require any support from its parent over the next two to three years given the outlook for its operating cash flows and capital expenditures. Operating cash flow is expected to decline sharply in 2002 due to large one-time income tax benefits included in net income, but should rebound in 2003. Free cash flow deficits beyond 2002 are expected to be minimal (around $10 million), and can be easily debt financed without negatively impacting leverage. Dividend payments to its parent will only be paid to the extent that there is sufficient excess cash flow after capital expenditures and such that the target capital structure is maintained. This provides ANCA with a high degree of financial flexibility. Over the medium term, the fixed-charges coverage is expected to remain between 2.0 times to 2.5 times, while cash flow/debt should remain above 0.20 times.

Ongoing challenges facing ANCA include: (1) the cumbersome regulatory environment in Alberta and significant time lags associated with rate decisions (often one-year delay); (2) the low regulated rates of return in Canada, which negatively impact earnings and cash flows; and (3) the negative impact on net earnings and ROE associated with the fact that the Company's net capital asset amount used for income tax purposes is lower than that allowed for regulatory purposes. As a result, the Company must pay higher federal income taxes than it is allowed to recover through customer rates.

RATING CONSIDERATIONS

Strengths:

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

Challenges:

- Parent's current credit and liquidity concerns
- Cumbersome regulatory environment with material lags
- Low regulated rates of return; allowed ROE sensitive to interest rates
- Negative impact on earnings and ROE of inability to recover all income taxes in customer rates

FINANCIAL INFORMATION

	12 mos. ended	For the year ended December 31	
	March 2002	2001	2000R*
Fixed-charges coverage (times)	2.37	1.97	1.87
% net debt in capital structure (1)	54.5%	56.3%	56.7%
Cash flow/total net debt (times) (1)	0.29	0.28	0.10
Cash flow/capital expenditures (times)	1.17	1.19	0.78
Net income (before extras.) ($ millions)	16.5	12.1	(1.7)
Operating cash flow ($ millions)	105.1	114.3	35.0
Electricity throughputs (GWh)	23,563	23,641	7,909
Operating margin	30.6%	29.7%	21.1%
Return on average common equity	5.3%	4.2%	(0.7%)
Average coupon on long-term debt	n/a	8.66%	n/a

* For four months ending December 31. (1) Debt is net of cash balances.

THE COMPANY

Aquila Networks Canada (Alberta) Ltd. (formerly UtiliCorp Networks Canada (Alberta) Ltd.) began operating in September 2000, following the acquisition of TransAlta Utilities Corporation's electricity distribution and retail assets in Alberta. The Company subsequently sold the retail electricity operations to EPCOR Utilities Inc. The Company's franchise region is located in central and southern Alberta. The Company is wholly owned by Aquila, Inc., a U.S.-based, multinational diversified energy company active in electricity and gas distribution, and energy-related services. Aquila is not providing any guarantees to the Company.

AUTHORIZED PAPER AMOUNT Limited to $112.5 million.

Aquila Networks Canada (British Columbia) Ltd.

Current Report: July 10, 2002
Previous Report: November 20, 2001

Geneviève Lavallée, CFA / Noreen Chan, CFA
416-593-5577 x2277 / x2266
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
BBB (high)	Stable	Confirmed	Secured Debentures *
BBB (high)	Stable	New Rating	Corporate Rating**

*Guaranteed by Aquila, Inc. ** Highest rating applicable to the direct obligations of the Company with no parent guarantee.

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996	1995
Secured Debentures *	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	A (low)
Corporate Rating**	BBB (high)	NR	NR	NR	NR	NR	NR	NR

* Guaranteed by Aquila, Inc. ** Highest rating applicable to the direct obligations of the Company with no parent guarantee.

RATING UPDATE

DBRS is confirming Aquila Networks Canada (British Columbia) Ltd.'s ("ANCBC" or "the Company") secured debentures at BBB (high), with a Stable trend. These secured debentures have a parent guarantee. DBRS is also assigning a corporate rating of BBB (high), with a Stable trend, to ANCBC.

ANCBC's earnings and operating cash flows improved in 2001 and during the first quarter of 2002, driven by the performance-based regulation and the Company's low-cost, hydro-based generation. However, as expected, ANCBC posted free cash flow deficits due to the ongoing sizeable capital expenditure program, including the Kootenay 230 kV transmission system development project, to be completed by summer 2003 (at an estimated cost of $100 million). Free cash flow deficits have been financed through a combination of debt and equity such that the capital structure has been maintained close to the deemed capital structure of 60%/40% debt/equity.

ANCBC's balance sheet improved significantly in Q1 2002 to 52% debt/capital as a result of a $15 million equity issue in February 2002. Over the short term, however, its key debt and interest coverage ratios are expected to weaken, and leverage will move back up to historical levels (closer to 60%) as capital expenditures are projected to double to about $80 million per year over the 2002-2004 period. Over the longer term, ANCBC's earnings outlook and financial profile remains favourable given its fundamentals, including its low-cost generation base, its diverse customer base, and the progressive regulatory environment in which it operates. One of the Company's challenges over the near term is related to the liquidity concerns of its U.S. parent and a potential downgrade of its U.S. parent's ratings. This could impact the level of financial support available to ANCBC should the Company require it.

RATING CONSIDERATIONS

Strengths:

- Low-cost, competitive hydroelectric generation base
- Secure, reasonably priced electricity supply contracts
- Diversified customer base
- Progressive regulatory environment

Challenges:

- Parent liquidity concerns and potential downgrade
- Large capital projects planned
- Earnings sensitive to interest rates via approved ROE
- Small size

FINANCIAL INFORMATION

	12 months	For years ended December 31				
	Mar. 2002	2001	2000	1999	1998	1997
Fixed-charges coverage (times)	2.61	2.41	2.19	2.20	2.22	2.70
% debt in the capital structure (incl. debt equiv)	52.0%	57.4%	62.4%	59.1%	61.3%	59.1%
Cash flow/total debt (times) (incl. debt equiv)	0.17	0.12	0.10	0.11	0.09	0.12
Cash flow/capital expenditures (times)	0.81	0.60	0.61	0.56	0.45	0.82
Net income ($ millions)	19.0	16.7	12.5	12.0	10.9	12.5
Operating cash flow ($ millions)	32.3	25.1	22.1	19.5	14.6	18.6
Electricity sales (millions of kWhs)	2,766	2,731	2,717	2,646	2,617	2,628
Electric revenues (1) (cents per kWh sold)	5.32	5.25	4.96	4.72	4.71	4.67
Variable costs (2) (cents per net gen kWh sold)	2.83	2.84	2.72	2.60	2.48	2.33
Fixed costs (cents per net gen kWh sold)	1.74	1.72	1.68	1.67	1.72	1.65
Pre-tax margin (1) (cents per kWh sold)	0.48	0.45	0.31	0.25	0.28	0.35
Average coupon on long-term debt	8.15%	8.15%	7.96%	8.18%	8.85%	8.76%

(1) Excludes ancillary revenues. (2) Excludes income taxes.

THE COMPANY

Aquila Networks Canada (British Columbia) Ltd. is a vertically integrated utility that owns and operates four hydroelectric generating plants (totalling 205 MW) on the Kootenay River in south-central British Columbia. The Company provides electricity services to about 91,500 direct customers. The Company recently changed its name from UtiliCorp Networks Canada (British Columbia) Ltd. to reflect the parent company's name change in March of this year.

GUARANTOR Kansas City, Missouri-based Aquila, Inc. (formerly UtiliCorp United Inc.) is a large multinational utility involved in electric and natural gas services, electricity generation, and other energy-related services.

Brilliant Power Funding Corporation

Report Date: February 4, 2003
Press Released: February 4, 2003
Previous Report: August 31, 2001

Rebecca Adams / Nigel Heath, CFA / Greg Nelson
416-593-5577 x2229/x2228/x2224
radams@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
A (high)	Stable	Confirmed	Series A Project Bonds
A (high)	Stable	Confirmed	Series B Project Bonds

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996	1995
Series A Project Bonds	A (high)	A (high)	"A"	"A"	"A"	"A"	"A"	NR
Series B Project Bonds	A (high)	A (high)	NR	NR	NR	NR	NR	NR

RATING UPDATE

DBRS is confirming the ratings of Brilliant Power Funding Corporation ("BPFC") at A (high), with a Stable trend. The ratings are being confirmed based on the improved fundamentals of the project since the inception of the rating in 1996. BPFC is a very low-cost producer of hydro-electric power in the Kootenay region of British Columbia. The increased discrepancy between BPFC's cost of production and the market value of the power produced reduces the concern associated with the fact that Aquila Networks Canada (British Columbia) Ltd. ["Aquila Networks Canada," formerly known as West Kootenay Power Ltd., and rated BBB (high), Stable trend] is the purchaser of all available power generated under a long-term "take or pay" contract. In addition, with rising debt service coverage ratios and the increasing importance of Powerex [the non-guaranteed export subsidiary of British Columbia Hydro & Power Authority ("BC Hydro") that serves as a backup power purchaser] to BC Hydro, alternative purchasers of power at higher prices are readily available. Life extension and upgrade initiatives for the facility, scheduled to be substantively completed by the end of 2002, will also positively affect the credit quality of BPFC, notwithstanding the planned issuance of additional debt (Series C Bonds) that will rank *pari passu* with the Series A and B Bonds. The B.C. government's new Energy Plan (announced in November 2002) is also unlikely to affect BPFC, given its stable contractual arrangements and low-cost generation.

The main challenge BPFC must contend with is the lack of control over the credit strength of its only customer, Aquila Networks Canada. In addition, consolidated leverage is likely to remain relatively high (approximately 68%). Although coverage ratios are gradually improving and becoming more comparable to other electric utilities, they remain consistent with the Company's narrow operating focus.

RATING CONSIDERATIONS

Strengths:

- Low-cost electricity generation
- Long-term "take or pay" contract with Aquila Networks Canada
- Back-up sales agreement with BC Hydro's subsidiary, Powerex
- Reserve funds covering six-month's debt service and operating costs during short-term contract disruptions
- Implied support by the Province of British Columbia [the "Province," rated AA (low)]

Challenges:

- Highly dependent on the credit worthiness of its only customer, Aquila Networks Canada, and B.C. Hydro
- High leverage and relatively weak coverage ratios compared to other electric utilities
- Single asset facility

FINANCIAL INFORMATION

	12 mos. ended	3 mos. ended	For years ended March 31				
(Columbia Basin Power Company)	June 2002	2002	2001	2000	1999	1998	1997 (1)
Debt service coverage (times)	2.08	2.02	1.53	1.43	1.40	1.35	1.37
EBIT interest coverage (times)	1.31	1.48	1.41	1.29	1.25	1.19	1.18
Cash flow-divid./capital expenditures (times)	0.28	0.22	0.13	0.36	0.35	0.35	0.76
% debt in capital structure	66.8%	65.7%	70.1%	69.9%	69.0%	68.1%	67.5%
Operating income ($ millions)	14.0	13.6	12.0	10.8	10.4	9.9	8.5
Net income ($ millions)	4.7	4.6	3.7	2.5	2.2	1.6	1.3
Operating cash flow ($ millions)	11.0	8.8	6.3	4.9	4.5	3.9	3.2
Unit revenues (cents per kWh sold)	3.15	2.87	2.79	2.52	2.38	2.48	2.28
Total costs (cents per kWh sold)	2.56	2.55	2.32	2.22	2.12	2.28	2.10
Pre-tax margin (cents per kWh sold)	0.59	0.32	0.47	0.30	0.26	0.20	0.18

(1) 11-month period since inception.

Note: Due to the structured nature of debt instruments, the above ratios are not directly comparable to Canadian utilities.

THE COMPANY

Brilliant Power Funding Corporation was established in 1996 to hold legal title to the real and tangible property comprising the Brilliant Dam and to finance the Brilliant Dam assets (located in the southern interior of B.C.), in both cases as agent and nominee for Columbia Power Corporation ("CPC") and CBT Power Corp., both of which are ultimately owned by the Province of British Columbia. The Columbia Basin Power Company, an unincorporated joint venture between Columbia Power Corporation and CBT Power Corp., was also established in 1996 to acquire and operate the Brilliant Dam and its related assets. All electricity currently produced at the Brilliant Dam is sold to Aquila Networks Canada.

British Columbia Hydro & Power Authority

*The rating is a flow-through of the Province of British Columbia, which conducts all of BC Hydro's financing activities.
This report specifically analyzes BC Hydro.

Report Date: November 29, 2002
Press Released November 29, 2002
Previous Report: September 5, 2002

Matthew Kolodzie, CFA / Geneviéve Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING*

Rating	Trend	Rating Action	Debt Rated
R-1 (middle)	Stable	Confirmed	Short-term liabilities
AA (low)	Stable	Confirmed	Long-term liabilities

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Short-term liabilities	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)
Long-term liabilities	AA (low)	AA (low)	AA (low)	AA (low)	AA	AA	AA

RATING UPDATE

The ratings for British Columbia Hydro & Power Authority's ("BC Hydro" or the "Utility") are a flow-through of the Province of British Columbia's rating, as the Utility's debt securities are direct obligations of the province. As a regulated utility, BC Hydro has historically generated relatively stable earnings and cash flow year over year. However, over the past two years, BC Hydro's electricity trading operations have contributed to significant earnings volatility. For example, following a year with record EBIT in F2001, supported by historically high power prices in the western U.S. and Alberta, EBIT in F2002 hit its lowest level in well over ten years, brought on by poor hydrologic conditions and weaker energy prices in BC Hydro's energy trading market. Leverage increased to over 80% in F2002 as a result of a free cash deficit flow, which was brought on by a significant drop in operating cash flow and high capital expenditures. While debt levels near 80% are high and constrain profitability, cash flow to debt and coverage ratios remain adequate for a regulated utility.

BC Hydro's key strengths are: (1) its predominately hydro-based generation capacity, which produces relatively low-cost power, and (2) its ability to benefit from power arbitrage through utilizing its storage capacity to purchase less expensive off-peak power and sell power at higher on-peak prices.

Earnings sensitivity to hydrologic conditions and electricity prices in key energy trading markets, along with one of the highest government levy burdens in Canada are among the Utility's most significant challenges.

A return to normal hydrologic conditions will lead to moderately stronger cash flows and improved coverage ratios. However, high capital expenditures over the next few years, together with the required dividend payments to the province, will likely lead to free cash flow deficits and higher debt levels over the near term. Earnings volatility will likely decline over the longer term, as earnings from energy trading are expected to decline due to reduced margins from a maturing market.

RATING CONSIDERATIONS

Strengths:

- Debt securities are direct obligations of the Province
- Low-cost hydro-based generation with substantial storage capacity
- Operating cash flows typically sufficient to finance capital expenditures and dividend payments to the Province
- FERC marketing licence enhances access to U.S. markets
- Interconnections with U.S. and Alberta support energy trading

Challenges:

- Excessive debt levels constrain profitability
- Exposure to foreign exchange rates
- Earnings sensitivity to hydrological conditions
- Heavy government levy burden
- Lack of access to equity markets
- Credit risk and litigation with utilities in California

FINANCIAL INFORMATION

	12 months ended	Years ended March 31				
	Sept. 2002	2002	2001	2000	1999	1998
EBIT interest coverage (times)	1.49	1.54	2.40	1.91	1.64	1.65
Net debt in the capital structure (1)	81.5%	81.0%	78.6%	82.2%	85.1%	85.3%
Cash flow/net debt (times)	0.09	0.10	0.15	0.13	0.10	0.10
Cash flow/capital expenditures (times)	1.05	1.22	2.78	2.58	2.12	2.55
Net income (bef. extras.) ($ millions)	235	258	859	545	407	440
Operating cash flow ($ millions)	660	671	919	912	733	708
Electricity sales (millions of kWhs)	74,646	68,467	72,031	69,852	64,506	56,460
Electricity revenues (cents per kWh sold)	-	9.11	10.87	4.91	4.65	4.42
Variable costs (cents per net gen kWh sold)	-	1.82	2.53	1.10	1.10	0.89
Fixed costs (cents per net generated kWh sold)	-	1.93	1.90	2.01	2.17	2.89
Average coupon on long-term debt	-	6.80%	7.80%	8.10%	7.70%	8.50%

(1) Excluding customer contributions and Columbia River Treaty.

THE COMPANY

British Columbia Hydro & Power Authority, a Crown corporation of the Province of British Columbia, generates, transmits, and distributes electric power in BC. In April 2002, the Utility began operating under three separate lines of business: (1) Generation; (2) Transmission; and (3) Distribution, and three service groups: (1) Field Services; (2) Engineering Services; and (3) Shared Services. In November 2002, the B.C. government announced its new Energy Plan. The plan outlines the formation of a new Crown corporation, BC Hydro Transmission Corp., which will operate the transmission grid. Transmission assets will remain with BC Hydro.

AUTHORIZED COMMERCIAL PAPER LIMIT $1.4 billion under the Provincial Fiscal Agency Loan Program.

Bruce Power Limited Partnership

Report Date: January 30, 2003
Press Released: January 30, 2003

Walter Schroeder, CFA / James Jung, CFA
416-593-5577 x2246
jjung@dbrs.com

RATING

This is a background report on Bruce Power, used in support of the TransCanada PipeLines and Cameco ratings.

SUMMARY

Under the proposed sale of British Energy plc's ("BE") remaining 82.4% interest in Bruce Power Limited Partnership ("Bruce" or the "Company"): (1) TransCanada Pipelines Limited will acquire 31.6% of Bruce; (2) Cameco Corporation will raise its interest to 31.6% from 15%; (3) The Ontario Municipal Employees Retirement System ("OMERS," the Ontario pension plan) will acquire a 31.6% interest; and (4) Bruce's associated unions will increase their holdings to 5.2%. With the assumption that the two nuclear units at Bruce A station are successfully returned to service (in addition to the four units that are operating), the profit potential to the new owners is substantial. At 90% load factor, the return could be around $300 million per annum (before financing and taxes), assuming average power rates of $43/MWh and operating cost of $35/MWh. The positive factors are: (1) Bruce does not have the risks connected with decommissioning and spent fuel disposal, which remain with Ontario Power Generation Inc. ("OPG"). With a nuclear plant, these are usually among the main risks. (2) The remaining life of the plant is long (2014 to 2017), and chances of a life extension are favourable. (3) Total generation capacity of Bruce B is expected to increase by 150 MW to 3,360 MW by 2005 due to fuel enhancements and turbine improvements. (4) Bruce has a high level of community support in the Bruce peninsula where it is located. As a result, there is positive political support for plant operation, unlike the situation at Pickering where there is a mixed environment. (5) The Bruce nuclear unit is one of the largest nuclear plants in the world, and is expected to further improve operating efficiencies Bruce B's total output has continued to increase over the past several years – 22.5 billion kWh in 1999, 23.4 billion kWh in 2000, and 24.1 billion kWh in 2001. There are large fixed costs in operating a nuclear unit, and in general, the fixed costs per unit of output fall as the output increases. However, there are a series of risks connected with operating the Bruce nuclear facility: (1) Refurbishing nuclear plants that have been shut down is challenging due to the need for safety and precautions. (2) Pressure tubes and boilers are the key components that could shorten plant lives. (3) There has been substantial government interference with the electricity market in Ontario, which makes returns uncertain. (4) As a result of the proposed sale, Bruce will lose the support of BE's nuclear facility knowledge and operational experience (5) Bruce is concentrated in one market, producing power from one nuclear complex. Loss of one of the six operating units for any length of time would have a major impact on profitability. Note that the interest expense related to the acquisition of Bruce is a capital cost to the owners, and not Bruce Power Limited Partnership. The potential profitability near $300 million before capital costs shows the substantial potential of Bruce, with most of the challenges to attain this profitability not insurmountable.

CONSIDERATIONS

Strengths:

- Expected strong, stable operating performance
- Long remaining plant life
- Expected increase in generation capacity per reactor
- Ongoing improvement in operating efficiency
- Decommissioning and fuel costs responsibility of OPG
- Favourable community support
- Expected stable long-term electricity prices in Ontario

Challenges:

- High cost and complexity of nuclear refurbishment
- Limited operating track record
- Pressure tubes and boiler constrain life of plants
- Loss of BE as a partner
- Substantial government interference
- Dependence on one generation site in one market

FINANCIAL INFORMATION

Revenue Potential - Bruce B (790 MW capacity x four reactors) and Bruce A (1,500 MW)

Load factor	100%	90%	82%
($ millions)			
Operating profit from Bruce B	360	274	204
Operating profit from Bruce A	171	130	97
Total operating profit	531	404	301
Interest on debt of owners ($1,175 millions x 7%)	(82)	(82)	(82)
Return to owners	448	322	219

(1) Average wholsale price at $43/MWh .
(2) Operating costs at $30/MWh for 100%, $32/MWh for 90%, and $34/MWh for 82%.

THE COMPANY

Bruce Power Limited Partnership operates one of the largest nuclear plants in the world, with a total capacity of approximately 6,000 MW (including 3,000 of laid-up capacity) Bruce B station has four units operating at 790 MW each, while Bruce A station is being refurbished (two units 750 MW each) for restart in the summer of 2003. Bruce A units have been laid up since 1995 (unit 2) and 1997/1998 for the remaining units. Two of the four units are being started up. BE is selling its 82.4% position, such that ownership of the plant will be OMERS (31.6%), Cameco (31.6%), and Trans Canada Pipelines (31.6%), with the remaining 5.2% owned by the Power Workers Union Trust No.1 (4%) and the Society of Energy Professionals Trust (1.2%).

Canadian Utilities Limited

Report Date: November 18, 2002
Press Released: November 14, 2002
Previous Report: August 15, 2001

Geneviève Lavallée, CFA/Matthew Kolodzie, CFA
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
"A"	Stable	Confirmed	Corporate Debt
Pfd-2 (high)	Stable	Confirmed	Preferred Shares*
Pfd-2	Stable	New Rating	Preferred Shares

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (middle)	NR	NR	NR
Debentures	"A"	"A"	"A"	A (high)	NR	NR	NR
Preferred Shares*	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-1 (low)	NR	NR	NR
Preferred Shares	Pfd-2	NR	NR	NR	NR	NR	NR

* Preferred shares held by Canadian Utilities Limited, but direct obligations of the regulated operating subsidiaries of CU Inc.

RATING UPDATE

The ratings on Canadian Utilities Limited ("CUL" or the "Company") are confirmed as above, and a new rating of Pfd-2, with a Stable trend, is assigned to any new preferred shares, which are direct obligations of CUL only. CUL continued to generate relatively strong and stable recurring earnings and operating cash flows for the 12 months ended September 30, 2002, due to the Company's diversified asset mix. The impact of low electricity prices in Alberta on the Company's merchant power portfolio was partially offset by the earnings impact of colder weather on its regulated portfolio. The Company's percentage of DBRS-adjusted debt in the capital structure was slightly lower relative to 2001, while its key cash flow and coverage ratios remained strong.

Over the medium term, it is expected that CUL earnings and operating cash flows will remain relatively stable, with modest growth. In the near term, the Company will receive an earnings and cash flow boost from the four new generation projects coming on line over the next 12 months, while economic growth in the Company's franchise areas will likely be the primary driver of growth over the medium term. It is expected that the Company's operating cash flows over the next two to three years will continue to be insufficient to internally fund DBRS-projected capital expenditures of about $550 million/year. Free cash flow deficits are expected to be funded through a combination of debt, preferred shares and common equity such that the capital structure and key cash flow and coverage ratios remain relatively stable. As CUL's risk profile increases with growth in non-regulated activities, gradual improvement in key ratios will be required to maintain the current rating.

Near term risks to the Company's earnings and cash flows include its merchant power exposure in Alberta given the lower electricity price environment and the higher gas prices, and the financial difficulties of one of the counterparties with whom it has a contract for the sale of power from the Barking plant in the U.K.

RATING CONSIDERATIONS

Strengths:

- Regulated utilities provide stability
- Increasing geographic diversification
- Low leverage for a holding company structure
- Strong franchise area, favourable market conditions

Challenges:

- Growing non-regulated portfolio increases risk profile
- Regulatory risk
- Earnings sensitive to weather and interest rates
- Increased business risk from PPAs

FINANCIAL INFORMATION

		12 months ended	For the year ended December 31				
Consolidated basis		Sept.-02	2001	2000	1999	1998	1997
Fixed-charges coverage (times)		2.60	2.56	2.60	2.54	2.44	2.36
Cash flow/total adj. debt (times) (1)		0.18	0.20	0.19	0.20	0.18	0.18
Cash flow/capital expenditures (times)		0.92	0.87	1.21	1.51	1.14	1.27
% adj. debt in capital structure (1)		56.2%	57.3%	59.3%	59.0%	61.1%	61.5%
Segmented income* - utilities (gas & electric)	29%	86.6	73.9	77.2	92.4	155.2	151.5
- power generation	24%	71.7	94.7	96.5	67.2	26.1	20.9
- other businesses	23%	71.0	60.3	53.1	44.1	14.2	12.2
- corporate/elim/extras	24%	73.9	8.2	0.6	(3.6)	(5.3)	(3.1)
Net income ($ millions, after pfd)		303.2	237.1	227.4	200.1	190.2	181.5
Operating cash flow ($ millions)		460.0	500.4	490.0	465.1	425.7	401.6
Total electricity sales (GWh)		13,748	13,689	14,053	13,765	12,658	12,437
Gas volume throughputs (bcf)		987.8	952.5	928.1	828.8	771.5	669.2

(1) Net of uncommitted cash holdings. Cumulative pfd shares = 70% equity weighting, retractable pfd - 100% debt.
* Net income breakdown in 2000 and 2001 not comparable to previous years due to internal reorganization.

THE COMPANY

Canadian Utilities Limited is a holding company whose principal operating subsidiaries include regulated electric and gas transmission and distribution utilities, as well as electricity generation assets in Alberta that are subject to legislatively mandated long-term power purchase arrangements (all held by CU Inc.), in addition to non-regulated subsidiaries and holdings in England, Australia and Canada. ATCO Ltd. owns 52% of Canadian Utilities Limited.

AUTHORIZED PAPER LIMIT: Cdn$200 million.

Churchill Falls (Labrador) Corporation Limited

Current Report: July 30, 2002
Previous Report: October 3, 2001

Geneviève Lavallée, CFA / Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	First Mortgage Bonds - Series A, B

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
First Mortgage Bonds - Series A, B	"A"	"A"	"A"	A (low)	A (low)	A (low)	A (low)

RATING UPDATE

DBRS is confirming the rating on Churchill Falls (Labrador) Corporation Limited's ("CF(L)Co" or "the Utility") First Mortgage Bonds as above. Given that 90% of the power generated is sold to Hydro-Québec under a long-term contract, the rating is largely based on the credit strength of Hydro-Québec. Hydro-Québec's rating is a flow-through of the Province of Québec. With variable costs at 0.12¢ per kWh, and all-in costs of producing power of 0.23¢ per kWh, CF(L)Co is possibly the lowest-cost generator of electricity in the world. Thus, DBRS expects Hydro-Québec would step in to support CF(L)Co in the unlikely event of any major operational or financial problems. This would be done to preserve the extremely attractive power rates (0.25¢ per kWh, excluding the Guaranteed Winter Availability agreement) in the long-term contract between Hydro-Québec and CF(L)Co that runs until 2041.

Although net income fell to $22 million in 2001, it is expected that CF(L)Co will generate net earnings close to $30 million over the longer term given the Guaranteed Winter Availability agreement with Hydro-Québec. Under the agreement, Hydro-Québec agreed to pay $1.1 billion in additional revenues for power over the remaining life of the original contract. The decline in net income in 2001 was due to lower energy sales and to higher maintenance costs. Despite the lower earnings, operating cash flows remained more than sufficient to internally fund capital expenditures and dividend payments, and to pay down debt. As a result, the debt to capital ratio fell to 43.3%, the lowest of any government-owned utility and lower than most investor-owned utilities. While annual capital expenditures are projected to remain close to $5 million in 2002 and 2003, and then rise to about $12 million in 2004 and 2005, (relative to previous annual capital expenditures of $2 million-$3 million), the Utility is expected to generate free cash flow surpluses, which will be available for debt reduction. The debt to capital ratio will continue to decline, with debt expected to be virtually eliminated by the end of 2007. Interest coverage and cash flow/debt should generally improve, but will remain much weaker than its investor-owned peers in the near term due to the unfavourable terms of the long-term electricity contract.

RATING CONSIDERATIONS

Strengths:
- Debt supported by long-term power contract
- Extremely low-cost hydro-based generating capacity
- Strong balance sheet, surplus cash flows
- Guaranteed Winter Availability contract

Challenges:
- Financially unfavourable long-term sales contract, with declining rates well below market prices to 2041
- Earnings sensitive to water levels
- High dividend pay-out expected to continue

FINANCIAL INFORMATION

	For the years ended December 31					
	2001	2000	1999	1998	1997	1996
EBIT interest coverage (times)	1.60	1.73	1.75	1.68	1.53	1.46
% debt in the capital structure	43.3%	46.7%	49.5%	53.8%	55.2%	56.4%
Cash flow/total debt (times)	0.14	0.14	0.14	0.12	0.10	0.09
Cash flow/capital expenditures (times)	8.63	13.11	21.61	16.53	21.57	15.21
Net income ($ millions)	22.2	27.3	29.4	29.4	21.9	19.4
Operating cash flow ($ millions)	38.8	43.6	45.8	45.6	39.2	36.6
Electricity sales (millions of kWhs sold)	32,361	34,601	33,807	36,878	33,131	28,411
Electricity revenues (cents per kWh sold)	0.29	0.28	0.27	0.25	0.26	0.28
Variable costs (cents per kWh sold)	0.12	0.10	0.08	0.07	0.08	0.09
Fixed costs (cents per kWh sold)	0.11	0.10	0.11	0.10	0.12	0.13
Avg. coupon on long-term debt	7.70%	7.71%	7.71%	7.71%	7.70%	7.70%

THE COMPANY

Churchill Falls (Labrador) Corporation Limited operates a 5,428 MW hydroelectric generating facility in Labrador. Under a fixed-price contract that runs until 2041, roughly 90% of the power generated is sold to Hydro-Québec. The Utility is 65.8%-owned by Newfoundland and Labrador Hydro, which is in turn owned by the Province of Newfoundland and Labrador. Hydro-Québec owns the remaining 34.2% of the Utility.

CU Inc.

Report Date: November 12, 2002
Press Released: November 11, 2002
Previous Report: July 30, 2001
Geneviève Lavallée, CFA/Matthew Kolodzie, CFA
416-593-5577 2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (high)	Stable	Confirmed	Unsecured Debentures & Medium Term Notes
Pfd-2 (high)	Stable	Confirmed	Preferred Shares*

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)
Unsecured Debentures	A (high)	A (high)	A (high)	AA (low)	AA (low)	AA (low)	AA (low)
Preferred Shares*	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-1 (low)	Pfd-1 (low)^	Pfd-1	Pfd-1

* The preferred shares, which will continue to be held by Canadian Utilities Limited, are direct obligations of the regulated operating subsidiaries of CU Inc.
^ On October 1, 1998, DBRS broadened its preferred share ratings scale, resulting in technical changes to the Company's preferred share credit rating.

RATING UPDATE

The ratings on CU Inc. (the "Company") are confirmed as above. CU Inc. continued to generate relatively strong and stable recurring earnings and operating cash flows for the 12 months ended September 30, 2002, due to the regulated nature of its businesses and the lack of any significant negative rate decisions. Modest growth in earnings was recorded for the 12 months ended September 30, 2002, primarily due to the colder weather. Net earnings and operating cash flows fell somewhat in 2001 despite the growth in earnings related to the Power Purchase Arrangements (PPAs), which came into effect on January 1, 2001, and a favourable rate decision relating to ATCO Gas and Pipelines South. The warmer weather in 2001 relative to 2000 more than offset these positive factors.

Over the medium term, it is expected that CU Inc.'s earnings and operating cash flows will remain relatively stable, with growth coming primarily from economic growth in the franchise areas. Ancillary services related to PPAs, as well as any incentives earned from exceeding availability targets, should provide incremental earnings. Volatility in earnings and cash flows from one year to the next will continue to be highly influenced by weather, as well as changes in interest rates through approved ROEs. It is expected that the Company's operating cash flows over the medium term will continue to be sufficient to cover capital expenditures of up to $350 million, but external financing will likely be required for capital expenditures above that amount. DBRS expects CU Inc.'s key cash flow and coverage ratios to remain stable, while its leverage will continue remain in line with deemed levels. The key ongoing risks facing CU Inc. remain dealing with regulatory risk, including the often-significant time delays in receiving regulatory decisions, as well as the business risks associated with the PPAs.

RATING CONSIDERATIONS

Strengths:

- Regulated businesses provide relative stability
- Track record of generating strong operating cash flow
- Diversified energy portfolio
- Low leverage for a holding company structure
- Strong franchise area

Challenges:

- Regulatory risk
- Earnings sensitive to weather and interest rates
- Increased business risk from PPAs
- Risk profile will increase as target availability/committed capacity of assets under the PPAs decline over life of contracts

FINANCIAL INFORMATION

	12 mos. ended	As at December 31*				
	Sept. 2002	2001	2000	1999	1998R	1997
Fixed-charges coverage (times)	2.56	2.31	2.40	2.56	2.55	2.45
% adj. debt in capital structure (1)	55.0%	54.9%	57.7%	55.9%	57.0%	58.8%
Cash flow/total adj. debt (times) (1)	0.18	0.18	0.18	0.20	0.19	0.18
Cash flow/capital expenditures (times)	1.28	1.43	1.52	1.93	1.50	1.41
Net income ($ millions) (before extras/after pfd)	161.9	150.3	153.1	156.0	155.3	151.6
Operating cash flow ($ millions)	329.4	334.2	366.6	366.1	353.1	335.4
Electricity sales (GWh)	9,414	9,288	10,392	10,068	10,188	10,089
Gas volumes throughtputs (bcf)	987.8	952.5	928.1	828.8	771.5	669.2
Return on avg. common equity (before extras.)	12.3%	11.4%	11.7%	12.3%	12.7%	13.1%
Average coupon on long-term debt	8.41%	8.41%	8.96%	9.20%	9.70%	9.72%

* 1993-98 pro forma, 1999 six months (January to June) combined ops of regulated gas + electric utilities, six months. (July to December) consolidated ops of CU Inc.
(1) Perpetual preferred shares given 70% equity weighting, retractable preferred treated as 100% debt.

THE COMPANY

CU Inc. is a holding company whose operating subsidiaries consist of regulated electric and gas transmission and distribution utilities that service most of Alberta, the Yukon, and the Northwest Territories, as well as electricity generation assets in Alberta that are subject to legislatively mandated long-term power purchase arrangements. CU Inc. is wholly owned by Canadian Utilities Limited (see separate report).

AUTHORIZED PAPER LIMIT Cdn$300 million.

Press Release

Dominion Bond Rating Service Limited

Date of Release: January 31, 2003 Energy

DBRS Downgrades Electricity Distributors Finance Corporation to A (low), Rating Remains "Under Review with Negative Implications"

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Under Review – Negative	Ownership Interests in Unsecured Debentures

DBRS is downgrading the certificates of the Electricity Distributors Finance Corporation ("EDFIN") to A (low) from "A." The trend is Stable. The rating remains "Under Review with Negative Implications," where it was placed on November 12, 2002, following the announcement by the provincial government to lower electricity bills.
The certificates represent undivided co-ownership interests in unsecured debentures issued by the five participating local distribution companies ("LDC" or "LDC Participants"). The obligations of the individual LDCs is several and not joint, and each LDC is liable only for its obligations and not for the obligations of any other LDC. The rating on EDFIN reflects the credit strength of the weakest LDC in the pool.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on the LDC participants and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the LDCs will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity, as such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base the 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the LDC's cash flows and coverage ratios over the medium term. The initial rating assigned to EDFIN had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that each LDC's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

The ratings will remain "Under Review with Negative Implications" until each of the municipal councils, representing the individual LDC's, votes on the resolution to declare whether their LDC will (1) remain as a commercial entity, as it has been since first incorporating in 1999; or (2) revert back to being a not-for-profit entity. Should any one of the LDCs revert back to being a non-for-profit entity (earning a zero return on equity), a further downgrade would be warranted, as the LDC's financial profile would become significantly weaker.

To date, only Barrie Hydro's municipal council has voted to remain as a commercial entity, the remaining municipal councils are expected to vote on the resolution in February 2003. If a council does not make its decision on the resolution by March 9, 2003, its LDC will automatically revert back to being a not-for-profit entity, as defined in Bill 210.

The rating continues to be supported by the following factors: (1) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; (2) favourable franchise areas with well-diversified customer bases, and moderate to strong load growth rates which should contribute to stable earnings growth over the medium to long term; and (3) shareholder municipalities that are financially sound and are able to provide additional equity injections or limit dividend requirements, if necessary, to further support their LDC capital structures. In addition, the LDCs will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on the EDFIN rating report will follow the release of the LDC's 2002 financial statements and the outcome of each municipality's vote on the resolution.

Electricity Distributors Finance Corporation

Current Report: July 22, 2002

Matthew Kolodzie, P.Eng., Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	New Rating	Ownership Interests in Unsecured Debentures

RATING HISTORY

	Current	2001	2000	1999	1998	1997
Unsecured Debentures	"A"	NR	NR	NR	NR	NR

RATING UPDATE

DBRS is assigning a rating of "A" to the certificates of the Electricity Distributors Finance Corporation ("EDFIN"). The trend is Stable. The certificates represent undivided co-ownership interests in unsecured debentures issued by the five participating local distribution companies ("LDC" or "LDC Participants") on a several basis. The rating on the unsecured debentures of EDFIN is supported by the credit strength of the LDC Participants. Each LDC Participant is currently rated at "A." The obligations of the individual LDCs is several and not joint, and each LDC is liable only for its obligations and not for the obligations of any other LDC.

The following key factors support the rating. Each of the LDCs (1) is involved in the regulated electricity distribution business in Ontario, which provides for a high degree of earnings and cash flow stability; (2) has a well-diversified customer base with a moderate load growth rate in its franchise area, which should contribute to stable long-term earnings growth; and (3) has moderate financial leverage, near 60% or less, and favourable coverage ratios which are expected to improve upon the full phase-in of the allowed 9.88% ROE in 2003. Additionally, (4) operating cash flows and current cash balances are expected to be sufficient to finance internal requirements at each LDC over the medium term. (5) Shareholders are financially strong Municipalities and are able to provide additional equity injections or limit dividend requirements, if necessary, to further support the LDC capital structures.

The rating is currently constrained by a number of challenges largely related to industry restructuring. (1) The most important challenge facing EDFIN, and the industry in general, is political/regulatory risk. For example, the phasing-in of new distribution rates over three years, instead of one, has constrained the earnings of distribution companies over the past two years. Consequently, LDCs' profitability and interest coverage will remain weaker until rate increases are fully phased in on March 1, 2003. (2) Uncertainty exists regarding the future regulatory framework beyond 2003, which will have a significant influence on medium-term profitability and cash flow growth at the LDCs. (3) Financial flexibility is limited by the inability of the LDCs to issue common equity (an LDC's equity base is limited to internal earnings growth or equity injections from its shareholder(s)).

RATING CONSIDERATIONS

Strengths:

- Improved regulatory environment in Ontario
- Regulated distribution provides earnings stability
- Favourable financial profile
- Favourable franchise areas and customer profiles
- Supportive shareholder municipalities

Challenges:

- Risk of political interference in the electricity sector
- Uncertainty related to the future regulatory framework
- Lack of formal dividend policies
- Ability to meet performance improvement targets
- Current lack of access to the public equity markets

FINANCIAL INFORMATION

	1999 Rate Base ($ millions)	Funds from EDFIN ($ millions)	Debt to Capital*	EBIT Interest Coverage (times)*	Cast flow to Debt*	Cash Flow to Capex (times)*
Enwin Powerlines Ltd.	161	50	60.8%	1.83	0.11	0.82
Richmond Hill Hydro Inc.	104	35	51.8%	5.01	0.18	1.78
Hydro Vaughan Distribution Inc.	181	35	56.8%	2.36	0.10	1.29
Markham Hydro Distribution Inc.	132	30	62.7%	1.74	0.10	0.79
Barrie Hydro Distribution Inc.	108	25	48.8%	2.16	0.16	1.58

* Forecast for year ended December 31, 2002.

THE COMPANY

Electricity Distributors Finance Corporation has been incorporated to purchase debentures and other prescribed instruments issued by participating local distribution companies and to sell undivided co-ownership interests in the debentures. The five participating LDCs are Barrie Hydro Distribution Inc., Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc., Richmond Hill Hydro Inc., and ENWIN Powerlines Ltd. The individual LDCs, or holding companies of the LDCs, are wholly owned by the municipalities in which they serve, with the exception of Richmond Hill Hydro which is jointly owned by Markham Hydro Distribution and Hydro Vaughan Distribution (50% each).

Emera Inc.

Report Date: December 6, 2002
Press Released: November 20, 2002
Previous Report: May 25, 2001

Matthew Kolodzie, CFA/Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

Rating

Rating	Trend	Rating Action	Debt Rated
BBB (high)	Stable	Confirmed	Medium Term Notes

Rating History

Rating History	Current	2001	2000	1999	1998	1997	1996
Medium Term Notes	BBB (high)	BBB (high)	NR	NR	NR	NR	NR

Rating Update

DBRS is confirming the rating for Emera Inc. ("Emera" or the "Company") as noted above, despite the recent unfavourable ruling by the Nova Scotia Utilities and Review Board ("UARB") on the 2002 rate application of Emera's largest subsidiary, Nova Scotia Power Inc. ("NSPI"). The negative impacts of the ruling were deemed to be short-term in nature, and not sufficient on their own to affect the long-term financial profile of the Company. Key factors supporting the rating confirmation are as follows: (1) Regulated operations, which account for over 90% of consolidated EBIT and assets, contribute to balance sheet and cash flow stability. In Q2 2002, Emera's second largest subsidiary, Bangor Hydro, received a favourable rate decision from its regulators, which will remain in effect until 2007. With allowed equity at the two regulated utilities in the 40% to 45% range, Emera's consolidated debt-to-capitalization ratio is expected to remain near 60% (DBRS-adjusted), which is reasonable for a primarily regulated energy company. (2) Emera's non-regulated businesses and investments complement electric utility operations and provides some diversification. (3) The two largest subsidiaries are expected to continue generating surplus free cash flow, in excess of capital expenditure requirements, and together will allow for annual distributions of $100 million to $120 million to parent Emera. (4) Emera is expected to utilize free cash flow to continue making strategic acquisitions that are accretive to earnings and relatively low risk.

Emera faces the following challenges: (1) Regulatory lag at NSPI by the UARB, since rate decisions by the UARB are not retroactive. The delayed 2002 rate decision (received October 2002), together with higher unit fuel costs, contributed to lower earnings at NSPI this year. In addition, the withdrawal of NSPI's 2003 rate application will pressure earnings next year. Emera will have to begin filing rate applications on a more frequent basis to enhance earnings stability over the longer term and improve NSPI's relationship with the UARB. In addition, the UARB has requested certain organizational changes with respect to the separation of duties between Emera and NSPI. (2) Future environmental risks associated with Nova Scotia coal-based generating facilities.

Proceeds from Emera's recent $156 million equity issue will be utilized to repay short-term debt and increase its equity at NSPI. The additional common equity will moderately improve the Company's financial flexibility.

Rating Considerations

Strengths:

- Regulated operations account for over 90% of EBIT and assets, and provide a degree of earnings/cash flow stability
- Operating subsidiaries typically generate sufficient cash flows to internally fund capex and dividends to Emera
- Non-regulated businesses/investments relatively low risk, complement electric utility operations

Challenges:

- Regulatory lag at Nova Scotia Power Inc. by the UARB
- Earnings sensitivity to weather and commodity prices
- Environmental risks associated with coal-based plants in Nova Scotia
- Competitive pressures developing in Nova Scotia

Financial Information

	12 months ended	For years ended December 31				
	Sept. 2002	2001	2000	1999	1998	1997
Fixed-charges coverage (times)	1.75	1.86	1.89	1.78	1.77	1.82
Adjusted debt in capital structure (1)	62.3%	62.6%	59.6%	61.0%	62.3%	62.8%
Cash flow/total adjusted debt (times) (1)	0.11	0.10	0.14	0.14	0.14	0.13
Cash flow/capital expenditures (times)	1.75	1.24	1.88	2.16	1.78	2.23
Operating income ($ millions)	286	269	251	244	239	253
Net income (before extras.) ($ millions)	114	126	114	112	97	102
Electricity sales (GWhs)	11,565	11,371	10,656	10,365	9,772	9,516
Operating cash flow ($ millions)	257	237	231	250	236	224

(1) Preferred shares treated as 30% debt equivalents.

The Company

Emera Inc. is a diversified energy and services holding company with three primary operating units: (1) wholly owned Nova Scotia Power Inc. (A (low), see separate report), a regulated integrated electric utility in Nova Scotia; (2) wholly owned Bangor Hydro-Electric Company, a regulated electricity transmission and distribution company in eastern and central Maine; and (3) Emera Energy, which includes Emera Fuels Inc., an unregulated oil distribution company with customers in Nova Scotia, New Brunswick and Prince Edward Island, a 12.5% interest in the Maritimes & Northeast Pipeline Limited Partnership ("A"; see separate report), and an equity interest in the infrastructure assets of the Sable Offshore Energy Project.

Press Release

Dominion Bond Rating Service Limited

Date of Release: January 31, 2003 Energy

DBRS Downgrades Enersource Corporation to A (low), Removed from UR-Negative

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Downgraded	Corporate Rating

DBRS is downgrading the corporate rating on Enersource Corporation ("Enersource" or the "Company") to A (low) from "A." The trend is Stable. The rating is removed from "Under Review with Negative Implications", where it was placed on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Enersource and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity. As such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Enersource had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

In December 2002, Mississauga city council had voted in support of Enersource remaining as a commercial entity as set out in the resolution that gave the shareholders the option to declared whether the Company would (1) remain as a commercial entity, as it has been since first incorporating in 1999; or (2) revert back to being a not-for-profit entity. Becoming a not-for-profit entity would have warranted a further downgrade, as its financial profile would have become significantly weaker.

Enersource's rating continues to be supported by the following factors: (1) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; (2) a favourable franchise area with a well-diversified customer base, and a moderate load growth rate which should contribute to stable earnings growth over the medium to long term; and (3) shareholders, the City of Mississauga and Borealis, that are financially sound and able to provide additional equity injections or limit dividend requirements, if necessary, to further support the Company's capital structure. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Enersource's rating report will follow the release of the Company's 2002 financial statements.

Enersource Corporation

Current Report: May 22, 2002
Previous Report: May 14, 2001

Matthew Kolodzie, P.Eng., Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Corporate Debt

RATING HISTORY

	Current	2001	2000	1999	1998	1997
Corporate Debt	"A"	"A"	NR	NR	NR	NR

COMMENTARY

The rating for Enersource Corporation ("Enersource" or "the Company") continues to be supported by the following factors. (1) Its regulated electricity distribution subsidiary, Enersource Hydro Mississauga ("EMH"), accounts for almost all of Enersource's operating income and 98% of its fixed assets. Regulated electricity distribution provides for a high degree of earnings and cash flow stability. (2) A well-diversified customer base with a moderate load growth rate will contribute to stable long-term earnings growth. (3) Operating cash flows and current cash balances will be sufficient to finance its internal requirements over the next three years. As a result, its balance sheet will remain strong, and key cash flow and coverage ratios should improve significantly. (4) The Company's shareholders are very strong financially and may provide equity injections to finance non-regulated activities such that the current capital structure is maintained.

The rating is currently constrained by a number of challenges largely related to industry restructuring. (1) The most important challenge the Company (and the industry) faces is political risk. As a result of the political pressures from the sharply higher electricity rates that would have resulted immediately from moving to the new regulatory environment, the Ontario Energy Board ("OEB") directed Local Distribution Companies ("LDCs") to phase in the initial rate increase required to generate the 9.88% target rate of return over a three-year period. Consequently, Enersource's profitability and interest coverage will remain weaker until rate increases are fully phased in. (2) Uncertainty exists regarding the future regulatory framework beyond 2003. It has yet to be decided if and how LDCs rate bases will be re-based, how approved ROEs will be set in the future, how deferred market transition costs will be recovered and whether productivity targets will be the same for all LDCs or be set for groups of utilities with similar characteristics. Enersource's medium-term profitability and cash flow growth will depend on how these issues are resolved. (3) Diversification beyond regulated distribution will increase business risk, although management is expected to maintain its conservative approach to investing in non-regulated activities. Over the medium term, non-regulated operations are expected to remain below 10% of consolidated assets, and similarly the impact of non-regulated activities on the stability of consolidated EBIT is expected to be minimal. (4) Financial flexibility is limited by the Company's inability to issue common equity (its equity base is limited to internal earnings growth).

RATING CONSIDERATIONS

Strengths:
- Involved primarily in the regulated electricity distribution
- Favourable franchise area
- Operating cash flows plus cash balances sufficient to cover capital expenditures over the next two years
- Financially strong parents
- Earnings growth potential from non-regulated subsidiaries

Challenges:
- Risk of political interference in the electricity sector
- Uncertainty related to the future regulatory framework
- Diversifying beyond regulated distribution
- Ability to meet performance improvement targets
- Lack of access to the public equity markets

FINANCIAL INFORMATION

	For the years ended December 31					
	2002P	2001	2000	1999	1998	1997
Fixed charges coverage (times)	1.86	1.12	1.51	59.29	45.07	-
% adjusted debt in capital structure	61.4%	62.1%	59.9%	-	-	-
Cash flow/total adjusted debt (times)	0.12	0.09	0.11	-	-	-
Cash flow/capital expenditures (times)	0.95	0.85	1.12	1.77	1.48	1.02
Operating cash flow ($ millions)	37.5	28.9	30.6	37.2	31.1	24.9
Operating margin	35.0%	29.6%	25.3%	27.9%	21.1%	9.9%
Return on average equity	3.6%	1.0%	1.4%	3.0%	2.1%	1.0%
Electricity throughputs (millions kWh)	7,395	7,249	7,002	6,821	6,505	6,288
Customer base	165,190	163,582	159,724	153,693	149,197	144,497

THE COMPANY

Enersource Corporation is a holding company that owns Enersource Hydro Mississauga ("EHM"), a regulated electricity distribution company, and Enersource Services Inc., a non-regulated holding company. Enersource Services Inc. consists of three wholly owned subsidiaries: (1) Enersource Telecom, a fibre-optic leasing company; (2) Enersource Hydro Mississauga Services, which provides utility solutions services to the utility sector, water heater rental/leasing, and is a 57% shareholder of First Source a retail electricity marketing company (43% held by Veridian Corporation); and (3) Enersource Technologies, which provides engineering and construction services. Enersource Corporation is 90%-owned by the City of Mississauga (see separate report - Regional Municipality of Peel) and 10%-owned by BPC Energy Corporation, a subsidiary of Ontario Municipal Employees Retirement System.

Credit Rating Report

ENMAX Corporation

Report Date: December 20, 2002
Press Released: December 20, 2002
Previous Report: November 30, 2001

Matthew Kolodzie, CFA / Geneviève Lavallée, CFA
416-593-5577 2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (low)	Stable	Positive	Unsecured Debentures*

RATING HISTORY

	Current	2001	2000	1999	1998	1997
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	NR	NR	NR
Unsecured Debentures*	A (low)	A (low)	A (low)	NR	NR	NR

*All unsecured debt is held by the City of Calgary.

RATING UPDATE

DBRS is confirming the long-term rating on ENMAX Corporation ("ENMAX" or the "Company") at A (low), the trend is now Positive. The short-term rating is confirmed as above. Key factors contributing to the trend change include: (1) The Company's prudent use of surplus cash to reduce debt since leveraging up its balance sheet in 2000, when it acquired two power purchase arrangements (PPAs) for $325 million. (2) The Company's ability to generate significantly stronger cash flows in the restructured Alberta electricity market, despite the volatility in spot prices. Even with a substantial drop in earnings and cash flow from 2001, largely due to lower electricity prices in the Power Pool of Alberta (4.1¢/kWh in 2002 year-to-date versus 7.2¢/kWh in 2001), ENMAX was still able to generate sufficient surplus cash to reduce its leverage to 16.5% and maintain strong coverage ratios, hence offsetting the increased business risk associated with the open electricity market. (3) The expectation that any future acquisitions will (a) be accretive to earnings, (b) be in regulated energy businesses or low-risk non-regulated energy-related businesses, and (c) allow the Company to maintain leverage at or below 50%. The Company's strong balance sheet provides it with sufficient financial flexibility to pursue strategic acquisitions.

ENMAX has been able to improve earnings and cash flow on the strength of its retail energy marketing operations, which is supported by low-cost power from its PPAs, fixed-price electricity supply contracts and the Regulated Rate Option (RRO). In addition, regulated transmission and distribution (about one-third of EBIT) provide relative earnings and cash flow stability. Earnings and cash flows are expected to remain strong over the near to medium term, based on these factors.

Despite ENMAX's strong financial profile, it faces several challenges. (1) With the expiry of one of its PPAs at the end of 2003, ENMAX will lose the source of relatively low-cost power for roughly 40% of its load. (2) Retail competition will intensify with the expiry of the existing RRO framework, beginning in 2004. Tighter margins on fixed-price contracts and the potential loss of customers to other retailers will pressure earnings. (3) Large industrial customers who have not signed retail contracts (roughly 18% of ENMAX's load) will continue to be a source of earnings and cash flow volatility.

Depending on the risk profile of acquisitions made by ENMAX over the near to medium term and the degree to which these acquisitions impact the Company's financial profile, an upgrade may be warranted.

RATING CONSIDERATIONS

Strengths:

- Regulated operations and fixed-price supply contracts provide a degree of earnings stability
- Strong balance sheet and favourable operating cash flows
- Financially strong parent (City of Calgary – AA)
- PPAs sufficient to supply fixed-price contracts

Challenges:

- Growing exposure to higher risk, non-regulated activities
- Expiry of existing RRO may result in customer losses
- Regulatory risk
- *Force majeure* associated with PPAs
- Limited access to equity markets reduces financial flexibility

FINANCIAL INFORMATION

	12 mos.	For years ended December 31				
	Sept. 2002	2001	2000	1999	1998	1997R
Fixed-charges coverage (times)	11.27	10.53	2.62	4.15	5.15	4.59
% debt in the capital structure	16.5%	19.1%	60.9%	30.5%	33.4%	38.1%
Cash flow/total debt (times)	1.55	2.05	0.14	0.51	0.59	0.45
Cash flow/capital expenditures (times)	2.06	3.81	1.09	1.26	2.93	3.23
Net income ($ millions) (before extras.)	164.6	249.6	44.5	44.6	65.2	52.1
Operating cash flow ($ millions)	301.2	424.6	75.4	73.0	93.2	77.4
Electricity sold (GWh)	9,678	9,242	7,500	7,162	6,980	6,867
Average coupon on long-term debt	7.57%	7.69%	7.77%	9.04%	9.08%	9.34%

R = Pro forma reflecting the January 1998 incorporation of ENMAX.

THE COMPANY

ENMAX Corporation is a holding company whose primary operating subsidiaries include the following: (1) ENMAX Power, a regulated entity that owns, operates, and maintains the electricity transmission and distribution system in Calgary and the surrounding area; (2) ENMAX Energy, a non-regulated entity that provides electricity and natural gas supply and services to over 425,000 customers in Calgary, Red Deer, and several other smaller communities in Alberta; and (3) ENMAX Encompass, which provides billing and customer service for ENMAX and other municipalities. ENMAX Corporation is wholly owned by the City of Calgary.

AUTHORIZED COMMERCIAL PAPER LIMIT $350 million.

EPCOR Utilities Inc.

Report Date: December 17, 2002
Press Released: December 16, 2002
Previous Report: November 16, 2001

Matthew Kolodzie, CFA / Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

Rating

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (low)	Stable	Confirmed	Senior Unsecured Debentures
Pfd-2 (low)*	Stable	Confirmed	Cumulative Redeemable Preferred Shares – Series A

* Preferred Share rating for EPCOR Finance Corporation.

Rating History

	Current	2001	2000	1999	1998	1997	1996
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	NR	NR
Senior Unsecured Debentures	A (low)	A (low)	A (low)	A (low)	A (low)	NR	NR
Cumulative Redeemable Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	NR	NR	NR	NR	NR

Rating Update

The ratings on EPCOR Utilities Inc. ("EPCOR" or the "Company") are confirmed as above. While EPCOR's business profile has become more risky as the Company has grown its non-regulated businesses, higher operating cash flow over the last two years has improved key financial ratios to compensate for this increased business risk. Key factors supporting EPCOR's rating include (1) the degree of earnings and cash flow stability provided by its regulated operations and power purchase arrangements (PPA); (2) a strong parent, the City of Edmonton (rated AA (high)), that is expected to protect its significant investment; and (3) favourable operating cash flows are expected to continue to contribute to strong coverage ratios and cash flow to debt over the medium term. Earnings are weaker this year, largely due to lower electricity prices in its service areas, but should generally improve over the medium term as its customer base grows, and new merchant generating capacity is brought into service.

The Company's financial flexibility remains somewhat constrained with 61% (DBRS-adjusted) debt-to-capital structure and lack of access to common equity markets. Leverage at this level is moderately high for a company expanding its non-regulated operations, and growing dividend requirements to the City of Edmonton will limit the amount of cash available to pay down debt. EPCOR has, however, scaled back its near-term capital expansion plans, with the cancellation of certain generation projects, and will be receiving $217 million from the securitization of its deferred revenue accounts, which will be used to reduce short-term debt.

EPCOR faces the following key challenges: (1) growing exposure to higher risk non-regulated activities, including (a) commodity price risk with retail energy marketing, and (b) merchant power risk as new generation capacity is built and the existing Rossdale PPA expires; (2) operating risks associated with meeting the supply commitments under PPAs in Alberta; and (3) regulatory risk and government intervention, such as the proposed legislation by the Ontario government, which may lead to the end of EPCOR's retail electricity marketing business in Ontario.

Rating Considerations

Strengths:

- Regulated businesses and PPAs provide earnings stability
- Favourable coverage ratios and cash-flow-to-debt
- Fiscally strong and supportive parent (City of Edmonton)
- Capacity expansions and acquisitions enhance earnings growth potential, joint ventures reduce development risk

Challenges:

- Growing exposure to higher-risk, non-regulated activities, including merchant power and retail energy marketing
- Government intervention and regulatory risk
- Lack of access to common equity reduces financial flexibility
- Environmental risks associated with coal-fired generation

Financial Information

	12 mos. ended	For years ended December 31				
	Sept. 2002	2001	2000	1999	1998	1997
Fixed-charges coverage (times)	2.67	3.12	1.98	1.84	1.93	1.82
% adjusted debt in the capital structure (1)	61.0%	63.2%	65.7%	61.1%	60.7%	62.3%
Cash flow/adj. total debt (times)	0.20	0.20	0.14	0.15	0.17	0.17
Cash flow/capital expenditures (times)	1.22	1.97	1.53	1.03	1.36	2.27
Net income ($ millions) (before extras.)	204.5	231.2	149.3	116.5	121.1	116.3
Operating cash flow ($ millions)	472.1	441.4	251.6	204.1	209.2	203.3
Electricity sales (millions of kWhs)	-	8,985	10,013	9,147	9,858	8,180
Electricity revenues (cents per kWh sold)	-	7.87	13.13	9.84	8.93	10.00
Average coupon on long-term debt	-	9.14%	9.14%	9.59%	10.27%	10.29%

(1) Preferred equity treated as 70% equity.

The Company

EPCOR Utilities Inc. is a holding company with ownership in various regulated and non-regulated operating subsidiaries. Regulated: The EPCOR power group of companies, which generate, transmit and distribute electricity; and EPCOR Water Services Inc - water purification and distribution operations. Non-Regulated: Ownership interests in independent power plants in Alberta, B.C. and Washington; retail energy services including electricity, natural gas and water heater rentals in Alberta and Ontario. EPCOR is wholly owned by the City of Edmonton.

AUTHORIZED PAPER LIMIT $500 million

Fortis Inc.

Report Date: January 14, 2003
Press Released: January 13, 2003
Previous Report: October 29, 2001
Matthew Kolodzie, CFA/Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

Rating

Rating	Trend	Rating Action	Debt Rated
BBB (high)	Stable	Confirmed	Unsecured Debentures
Pfd-3 (high)	Stable	Confirmed	Preferred Shares

Rating History

	Current	2001	2000	1999	1998	1997
Unsecured Debentures	BBB (high)	BBB (high)	BBB (high)	NR	NR	NR
Preferred Shares	Pfd-3 (high)	Pfd-3 (high)	Pfd-3 (high)	NR	NR	NR

Rating Update

DBRS is confirming the ratings on Fortis Inc. ("Fortis" or the "Company") as noted. The ratings take into consideration the underlying credit strength of the Company's operating subsidiaries. Fortis' key strength is its regulated electricity transmission and distribution operations, which provide a favourable degree of stability to earnings and cash flow.

Fortis has experienced significant earnings growth following several new investments/acquisitions. With expansion, the Company's business profile has become more risky as the proportion of consolidated EBIT from non-regulated operations has grown with (1) the addition of four new commercial and hotel properties, and (2) the deregulation of its Rankine generating station in Ontario. However, Fortis has continued to make significant investments in regulated electricity distribution and transmission with (1) the addition of two local distribution companies in Ontario, (2) the acquisition of the remaining 50% of Canadian Niagara Power in 2002, and (3) an increase in its equity investment in Caribbean Utilities Limited, Inc. As such, regulated utilities continue to contribute over 80% of consolidated EBIT.

Despite increasing debt levels to fund acquisitions and capital expenditures, Fortis' financial profile has improved modestly with continued growth in earnings and operating cash flow, and the issuance of $104 million in new equity over the 12 months ended September 30, 2002.

Expanding operations will continue to contribute to moderate growth in operating cash flow over the medium term and should cover dividend requirements. However, internally generated cash will likely remain insufficient to fund capital expenditures and acquisitions. Despite this shortfall, Fortis is expected to maintain a financial profile that is adequate for a BBB (high) primarily regulated energy company: (1) Future growth and acquisitions are expected to be financed with a combination of debt and equity such that DBRS-adjusted leverage will remain in the 60% to 65% range. (2) Moderate earnings growth from expanding operations should maintain favourable coverage ratios. (3) Improved operating cash flow will maintain a reasonable cash flow to debt. In addition, the Company's business profile is expected to remain such that regulated utility operations generate roughly 80% of consolidated EBIT. Fortis has indicated that the majority of its future expansion will be in regulated electricity distribution and small hydroelectric projects, which are relatively low-risk, and will provide a degree of stability to earnings and cash flow.

Rating Considerations

Strengths:

- Regulated operations account for over 80% of EBIT, providing a favourable degree of stability to earnings and cash flow
- Subsidiaries/operations in different regions provide geographic and regulatory diversification
- Subsidiaries experiencing steady growth in electricity demand

Challenges:

- Proportion of earnings from regulated utilities is declining
- Political/economic risks associated with foreign operations
- Regulated utility earnings sensitivity to interest rates
- Fortis is a holding company whose debt is structurally subordinate to debt in the operating companies

Financial Information

	12 mos. ended	For years ended December 31				
	Sept. 2002	2001	2000	1999	1998	1997
Fixed-charges coverage (times)	2.29	2.16	1.89	2.11	1.93	2.07
Adjusted debt in capital structure *	60.6%	63.8%	62.4%	61.7%	57.9%	58.4%
Cash flow/adjusted total debt (times)	0.12	0.13	0.09	0.10	0.12	0.14
Cash flow/capital expenditures (times)	0.65	0.80	0.49	1.07	1.04	1.47
Operating income ($ millions)	166.4	147.4	110.1	103.6	91.6	104.9
Net income (before extras., after pfd) ($ millions)	65.2	55.9	39.9	35.2	29.8	42.5
Operating cash flows (after pfd) ($ millions)	125.7	118.0	75.2	68.9	66.1	72.8
Electric utility EBIT	140.1	129.0	98.6	95.8	90.1	99.8
Non-electric utility EBIT	27.4	19.5	13.1	8.5	1.5	5.0

* Adjusted for equity treatment of hybrid securities.

The Company

Fortis Inc. is a holding company, focused primarily in electric utility operations. Utility subsidiaries include: 100% common share interest in Newfoundland Power; wholly owned Maritime Electric, wholly owned Canadian Niagara Power, and wholly owned Cornwall Electric. Fortis also owns four merchant power plants in New York (FortisUS Energy), a 51% interest in the Exploits River Partnership (a partnership with Abitibi Consolidated) a 95% interest in Belize Electric Company Limited (BECOL), a 67% interest in Belize Electricity Limited, and a 22% investment in Caribbean Utilities. Non-utility operations include wholly owned Fortis Properties, which owns and manages retail, office, and hotel properties in Newfoundland, Nova Scotia, and New Brunswick.

Great Lakes Power Inc.

Current Report: July 19, 2002
Previous Report: October 29, 2001
Matthew Kolodzie, P.Eng., Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
BBB (high)	Stable	Confirmed	Senior Unsecured Notes
R-1 (low)	Stable	Confirmed	Commercial Paper

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Senior Unsecured Notes	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

RATING UPDATE

Key factors supporting the rating confirmation for Great Lakes Power Inc. ("Great Lakes Power" or "the Company") are as follows: (1) approximately 95% of Great Lakes generating capacity is low-cost hydro-based and is increasing with recent acquisitions and new plants under construction; (2) the majority of the Company's electricity output is committed under long-term power sale agreements; and (3) debt levels remain reasonable for an electric utility.

Leverage increased slightly to 45.8% debt/capital at March 31, 2002, as a result of the Company's capital investment plan to double its operating earnings from its power business (largely financed with project mortgages and operating cash flow). This level of debt remains reasonable for an integrated electric company of this size. EBIT interest coverage improved to 2.80 times for the 12 months ended March 31, 2002, due to higher operating income from increased generating capacity and improved hydrology. With recent generation facility acquisitions, Great Lakes Power's business profile has changed to become more energy focused, as its energy operations now comprise roughly 50% of consolidated assets and more than two-thirds of earnings (versus 42% assets and 63% of income at December 31, 2000).

Great Lakes Power faces several key challenges: (1) Considerable uncertainty exists with the ongoing restructuring of the electricity industry in Ontario. Power generation is now exposed to open market competition, and transmission and distribution operations are subject to regulatory risk. (2) Earnings are sensitive to precipitation and water levels at its hydroelectric generating facilities. (3) Utility operations are relatively small compared to other Canadian electric utilities. (4) Investment holdings are relatively illiquid as they are primarily in affiliated, unlisted companies.

RATING CONSIDERATIONS

Strengths:

- Low-cost, largely hydro-based generating facilities
- Long-term power sales contracts for IPPs
- Growth opportunities associated with Ontario electricity restructuring
- Growing generating assets providing greater diversification

Challenges:

- Uncertainty related to Ontario electricity restructuring
- Illiquid investments in affiliated, unlisted companies
- Utility operations are relatively small
- Earnings sensitive to water levels

FINANCIAL INFORMATION

		Year ended December 31					
Consolidated results	Mar. 2002	2001	2000	1999	1998	1997	1996
Electric utility income ($ millions)	92.2	75.8	61.4	45.7	40.2	43.0	47.5
Investment income ($ millions)	44.6	39.0	36.5	51.5	47.8	63.7	48.4
Consolidated net income ($ millions) (1)	136.8	114.8	97.9	97.2	88.0	106.7	95.9
Operating cash flow ($ millions) (1)	136.8	120.2	112.0	115.6	111.0	113.9	109.2
% debt in capital structure	45.8%	43.7%	42.3%	42.2%	39.5%	37.8%	40.3%
Cash flow / total debt	0.10	0.10	0.11	0.12	0.13	0.14	0.13
Cash flow-divd. / capital expenditures (2)	(1.14)	0.62	1.74	1.10	2.36	(0.33)	0.22
EBIT interest coverage (3) (times)	2.80	2.23	2.10	2.23	2.13	2.34	2.21

(1) After convertible debenture interest. (2) Capital expenditures include other investments. (3) Includes equity income, capitalized interest/AFUDC.

THE COMPANY

Great Lakes Power Inc. consists of: (1) Energy assets, including (a) Great Lakes Power Limited ("GLPL"), involved in hydroelectric power generation, transmission and distribution in Sault Ste. Marie, Ontario; (b) a 50% interest in the Great Lakes Hydro Income Fund ("Income Fund"), which owns five hydroelectric generating facilities in Ontario, Quebec, British Columbia, Maine, and New Hampshire, (c) other power operations, including five hydroelectric generating facilities in Ontario, Quebec, and Louisiana and a natural gas cogeneration plant in northern Ontario; and (d) an energy marketing subsidiary, Brascan Energy Marketing Inc.; and (2) a $1.5 billion investment portfolio (about 49% of total assets) with substantial holdings in affiliated companies. Great Lakes Power Inc. is a wholly owned subsidiary of Brascan Corporation ("Brascan").

AUTHORIZED COMMERCIAL PAPER AMOUNT Limited to $100 million.

Hydro One Inc.

Report Date: December 17, 2002
Press Released: December 10, 2002
Previous Report: February 28, 2002

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
"A"	Negative	Trend Change	Senior, Unsecured Debentures

Geneviève Lavallée, CFA/Matthew Kolodzie, CFA
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING HISTORY

	Current	2001	2000	1999	1998	1997
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	NR	NR	NR
Senior, Unsecured Debentures	"A"	"A"	"A"	NR	NR	NR

RATING UPDATE

The ratings on Hydro One Inc.'s ("Hydro One" or the "Company") commercial paper and senior, unsecured debentures are confirmed at R-1 (low) and "A", respectively. The long-term trend is changed to Negative from Stable, while the short-term trend remains Stable.

The long-term trend change to Negative reflects the high level of political risk and uncertainty with respect to the Ontario electricity market and Hydro One's future over the medium term given the recent actions by the provincial government. The recently legislated rate cap on transmission and distribution in the Ontario electricity market will remain in effect until 2006, and will result in weaker earnings and operating cash flows for Hydro One than previously anticipated. However, the anticipated financial impact on Hydro One from the rate cap is not significant enough to warrant a downgrade from the current ratings. The Company derives two-thirds of its earnings from transmission, which will be much less affected by the rate caps than distribution. DBRS expects Hydro One's adjusted debt-to-capital ratio to increase only marginally over the medium term in the absence of the Province finding a strategic partner to hold a minority interest in Hydro One. Key cash flow and coverage ratios will likely weaken from current levels, but are expected to remain in the range considered acceptable for an "A"-rated regulated utility. A downgrade may be warranted if political intervention persists in the electricity market over the next 6 to 12 months that results in a further deterioration in Hydro One's financial profile.

Hydro One's financial results for the 12 months ended September 30, 2002, were somewhat weaker than in previous years, but remained generally acceptable for a regulated utility. Given Hydro One's current financial profile, DBRS believes that Hydro One has sufficient financial flexibility to deal with the challenges imposed by the provincial government. However, over the next six months, it faces a heavy term debt maturity schedule and, thus, increased refinancing risk. Given that (1) the debt maturing is held indirectly by the Province, (2) the Province is currently the sole shareholder, and (3) the Province has provided support to both Hydro One and Ontario Power Generation in the past to deal with financing difficulties, it is highly likely that the Province would continue to support Hydro One should it encounter difficulties refinancing these maturities.

RATING CONSIDERATIONS

Strengths:

- Involved primarily in regulated activities
- Attractive Ontario-based business franchise
- Cost savings and operating efficiencies from internal rationalization and MEU acquisitions

Challenges:

- Political risk
- Free cash flow deficits projected over medium term
- Heavy debt refinancing schedule

FINANCIAL INFORMATION

	12 mos. ended	For the year ended December 31				
	Sept. 2002	2001	2000	1999*	1998*	1997*
Fixed-charges coverage (times)	2.31	2.45	2.30	2.32	1.46	1.50
% adj. debt in the capital structure (1)	57.1%	56.1%	54.2%	54.6%	71.8%	75.0%
Cash flow/adj. total debt (times)(1)	0.13	0.14	0.15	0.15	0.09	0.09
Cash flow/capital expenditures (times)	1.11	1.25	1.53	1.34	1.43	1.86
Approved ROE	9.88%	9.88%	9.88%	9.35%	-	-
Net income ($ millions) (bef extras. after pfd.)	322	356	363	409	270	304
Operating cash flow ($ millions)	697	708	684	709	546	538
Electricity sold - distribution (GWh)	26,700	21,300	17,600	18,100	18,300	18,800
Electricity throughputs - transmission (GWh)	150,200	146,900	146,900	144,100	143,000	144,800

* 1999: 9 months Hydro One + 3-mos. allocation of Ontario Hydro results. 1997-1998: an allocation of Ontario Hydro results that reflect the operations of Hydro One.
(1) Adjusted for equity treatment of hybrid debt securities.

THE COMPANY

Hydro One Inc., one of the successor companies of the former Ontario Hydro, holds and operates transmission and distribution assets, as well as a fibre-optic network across most of Ontario. Hydro One is the second largest electricity distributor in Ontario based on distribution throughputs and the largest based on the number of customers. The Company is currently wholly owned by the Province of Ontario, although debt issued directly by Hydro One Inc. is not guaranteed by the province. The province is currently in the process of seeking a strategic partner(s) to purchase a minority interest in Hydro One.

AUTHORIZED PAPER AMOUNT Cdn$1 billion

Press Release

Dominion Bond Rating Service Limited

Date of Release: January 31, 2003 Energy

DBRS Downgrades Hydro Ottawa Holding Inc. to A (low), Rating Remains "Under Review with Negative Implications"

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Under Review – Negative	Corporate Rating

DBRS is downgrading the corporate rating on Hydro Ottawa Holdings Inc ("Hydro Ottawa" or the "Company") to A (low) from "A." The trend is Stable. The rating remain "Under Review with Negative Implications," where it was placed under on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Hydro Ottawa and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity. As such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Hydro Ottawa had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

The rating will remain "Under Review with Negative Implications" until Ottawa municipal council votes on the resolution to declare whether Hydro Ottawa will: (1) remain as a commercial entity, as it has been since first incorporating in 2000; or (2) revert back to being a not-for-profit entity. Should Hydro Ottawa revert back to being a not-for-profit entity, a further downgrade would be warranted, as the Company's financial profile would become significantly weaker. Remaining as a commercial entity would warrant the removal of "Under Review with Negative Implications" status.

The Ottawa City Council is expected to vote on the resolution in February 2003. If Council does not make a decision on the resolution by March 9, 2003, Hydro Ottawa will automatically revert back to being a not-for-profit entity, as defined in Bill 210.

Hydro Ottawa's rating continues to be supported by the following factors: (1) a favourable franchise area; (2) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; and (3) a strong supportive parent, the City of Ottawa, that is able to provide additional equity injections or limit dividend requirements, if necessary, to further support Hydro Ottawa's capital structures. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Hydro Ottawa's rating report will follow the release of the Company's 2002 financial statements and the outcome of the municipal council's vote on the resolution.

Hydro Ottawa Holding Inc.

Current Report: April 16, 2002

Geneviève Lavallée, CFA/Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	New Rating	Corporate Rating

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Corporate Rating	"A"	NR	NR	NR	NR	NR	NR

RATING RATIONALE

DBRS is assigning a new corporate rating of "A" to Hydro Ottawa Holding Inc. ("Hydro Ottawa" or "the Company"). The trend is Stable. The following key factors support the rating. (1) The Company will be primarily involved in the regulated electricity distribution business, which provides for a high degree of earnings and cash flow stability. Furthermore, the Company will not be involved in the more volatile retail energy marketing. (2) The Company operates in a high-density franchise area with a diversified, growing customer base, which results in lower average operating costs per customer, as well as more stable revenue growth. (3) Hydro Ottawa's operating cash flows and existing cash balances will be sufficient to finance its capital expenditures over the next two to three years. As a result, its balance sheet will remain strong, and key cash flow and coverage ratios should improve significantly. (4) Hydro Ottawa has a financially strong parent, the City of Ottawa (rated AA (high)), which is a potential source of support. Providing additional support to the rating are the various measures being introduced in the short term to improve operating efficiencies and achieve the performance-based regulation ("PBR") productivity targets.

The rating is currently constrained by a number of challenges largely related to industry restructuring. The most important challenge the Company faces is political risk. As a result of the political pressures from the sharply higher electricity rates that would have resulted immediately from moving to the new regulatory environment, the Ontario Energy Board directed Local Distribution Companies ("LDCs") to phase in the initial rate increase required to generate the 9.88% target rate of return over a three-year period. Consequently, Hydro Ottawa's profitability and interest coverage will remain weaker while the rate increases are fully phased in. DBRS expects the significant uncertainties with respect to industry restructuring could contribute to further political pressures that may adversely affect the profitability of the Company. Hydro Ottawa also faces significant uncertainty with respect to the regulatory framework beyond 2003, which could negatively impact its future financial position. An additional factor that is currently constraining the rating is the fact that no dividend policy has been set for the Company. Given Hydro Ottawa's lack of access to the public equity markets, this is an important consideration for its future financial position. If the dividend policy continues to provide Hydro Ottawa with sufficient flexibility to internally finance its capital requirements and if the near-term uncertainties do not materialize, an upgrade may be warranted.

RATING CONSIDERATIONS

Strengths:

- Involved primarily in regulated activities
- Favourable franchise area with high density population and diversified customer base
- Operating cash flows plus cash balances sufficient to cover capital expenditures over the next two to three years
- Financially strong parent

Challenges:

- Risk of political interference in the electricity sector
- No dividend policy has been set for Hydro Ottawa
- Uncertainty related to the future regulatory framework
- Profitability and interest coverage will remain weak over near term
- Lack of access to public equity markets

FINANCIAL INFORMATION

	For the year ending December 31					
				Pro forma	Pro forma	Pro forma
	2003P	2002P	2001	2000	1999	1998
Fixed-charges coverage (times)	2.36	1.69	NMF	NMF	3.10	5.20
% debt in capital structure	54.1%	56.4%	56.6%	57.3%	2.6%	2.9%
Cash flow/total debt (times)	0.17	0.12	0.11	0.10	2.22	1.95
Cash flow/capital expenditures (times)	0.65	0.54	0.68	0.83	1.21	1.01
Net income (bef extra.) ($ millions)	12.6	3.0	0.9	(0.7)	1.9	2.0
Operating cash flow ($ millions)	40.4	29.3	26.3	22.7	24.3	22.8
Operating margin	33.6%	18.6%	(3.9%)	(1.2%)	4.6%	4.4%
Return on average equity	9.2%	1.6%	0.5%	(0.4%)	0.5%	0.5%
Electricity throughputs (GWh)	7,384	7,239	7,351	7,006	7,061	6,733
Customer base	265,948	260,734	258,651	253,954	250,012	246,012

Pro forma reflecting the amalgamation of five area MEUs.

THE COMPANY

Hydro Ottawa Holding Inc. is a holding company with the following subsidiaries: Hydro Ottawa Limited, a regulated electricity distributor; Energy Ottawa Inc., an non-regulated company involved in hot water rentals, generations, and eventually energy management services; and Telecom Ottawa Limited, a new company expected to be involved in fibre-optic leasing, bulk Internet provider, virtual network provider, and data local exchange carrier. Hydro Ottawa Limited represents the consolidation of the former Ottawa, Nepean, Kanata, Gloucester, and Goulbourn.

Hydro-Québec

(The rating is based on the Provincial guarantee. This report specifically analyzes Hydro-Québec.)

Current Report: July 9, 2002
Previous Report: July 4, 2001

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Long-Term Debt
R-1 (low)	Stable	Confirmed	Commercial Paper

Geneviève Lavallée, CFA/Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING HISTORY	Current	2001	2000	1999	1998	1997	1996	1995
Long-Term Debt	"A"	"A"	"A"	A (low)	A (low)	A (low)	A (low)	"A"
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

UPDATE

The ratings are a flow-through of the ratings of the Province of Québec (see separate report), which unconditionally guarantees the majority of Hydro-Québec's ("the Company") debt. Hydro-Québec's operating income (DBRS-adjusted) was relatively unchanged in 2001, as higher revenues from ancillary businesses were offset by lower margins on export sales, and lower depreciation costs were offset by higher capital and property taxes. Lower interest costs were the primary contributor to the modest increase in net income. Despite the modest rise in net earnings, operating cash flows increased significantly (4.6%) and allowed the Company to generate another substantial free cash flow surplus. Given the lack of major acquisitions in 2001, Hydro-Québec was able to pay down debt by $1 billion. However, despite the debt paydown, the Company's leverage increased in 2001 as a result of the depreciation in the Canadian dollar and the FX translation impact on the balance sheet.

Over the medium term, Hydro-Québec's earnings and cash flow growth are expected to come from modest growth in domestic sales volumes and contributions from international investments and ancillary businesses. The recent rate decision for the Company's transmission division also provides support to the earnings outlook. Despite these positive factors, earnings and cash flow growth will continue to be constrained by the freeze on domestic rates until 2004. Furthermore, although Hydro-Québec is a very low-cost electricity generator, the wholesale price cap imposed on it for up to 165 TWh/year could constrain the Company's earnings growth if its power production costs rise above the 2.79¢/kWh cap. Little earnings growth is expected in the near term from trading due to the current low margins. However, Hydro-Québec's low cost structure and its ample water storage capability will continue to provide it with the flexibility to export power at peak rates, thereby improving export margins. Operating cash flows are expected to remain sufficient over the medium term to cover the projected capital investment program (annually $2.6 billion to $3.1 billion) and dividend payments, and pay down debt. Interest costs should continue to decline, although interest costs will remain sensitive to changes in the Canadian dollar/U.S. dollar exchange rate. Fixed-charges coverage should continue to gradually improve.

CONSIDERATIONS

Strengths:

- Debt is unconditionally guaranteed by province
- Low-cost, hydro-based own generation plus inexpensive power from Churchill Falls
- Water storage capacity allows for strategic energy trading
- Free cash flow surpluses projected over medium term
- Positioned to benefit from trend in energy convergence
- Access to NB, Ontario, and U.S. electricity markets

Challenges:

- High debt levels constrain profitability and contribute to weak interest coverage ratios
- Domestic rates frozen until 2004; wholesale price cap
- Sensitivity to water levels and FX exposure increase volatility of earnings and cash flows
- Limited interconnections restrict export capacity
- Natural gas a longer-term competitive threat

FINANCIAL INFORMATION

	12 mos. ended	For the year ending December 31					
	March 2002	2001	2000	1999	1998	1997	1996
EBIT interest coverage (times)	1.35	1.36	1.34	1.29	1.22	1.26	1.16
Net debt* in capital structure	74.2%	74.7%	73.6%	73.5%	74.8%	74.8%	75.6%
Cash flow/total debt (times)	0.08	0.08	0.08	0.07	0.06	0.06	0.05
Cash flow/capital expenditures (times)	1.53	1.77	0.90	1.25	1.03	1.11	1.00
Net income ($ millions)	1,043	1,108	1,078	906	679	786	520
Operating cash flow ($ millions)	3,247	3,406	3,256	2,779	2,343	2,357	2,039
Electricity sales (millions of kWhs)	n/a	195,026	190,080	171,712	161,373	162,533	163,402
Electricity revenues** (¢ per kWh sold)	n/a	5.60	5.35	4.95	4.96	4.88	4.68
Variable costs (¢ per net gen kWh sold)	n/a	2.23	1.98	1.88	1.75	1.41	1.15
Fixed costs (¢ per net gen kWh sold)	n/a	4.13	4.06	4.29	4.59	4.10	3.92
Average coupon on long-term debt	n/a	8.05%	8.82%	8.71%	8.80%	8.91%	9.13%

*Net of sinking fund assets. **Excludes ancillary revenues.

THE COMPANY

Hydro-Québec, a Crown corporation of the Province of Québec, generates, transmits, and distributes electricity in the Province of Québec. The utility has a 41% ownership interest (and an option on an additional 9%) in Noverco, which owns Gaz Métropolitain, a natural gas distributor in Québec.

AUTHORIZED PAPER AMOUNT Limited to US$2,250 million

The Manitoba Hydro-Electric Board

The rating is based on the provincial guarantee. This report specifically analyzes Manitoba Hydro.

Report Date:	October 23, 2002
Press Released:	October 23, 2002
Previous Report:	October 24, 2001

Matthew Kolodzie, P.Eng./Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Positive	Confirmed	Long Term Debt
R-1 (low)	Stable	Confirmed	Commercial Paper/T-Bills

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996	1995
Long Term Debt	"A"	"A"	"A"	"A"	"A"	"A"	"A"	"A"
Commercial Paper/T-Bills	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

RATING UPDATE

The ratings for The Manitoba Hydro-Electric Board ("Manitoba Hydro" or the "Utility") are a flow-through of the ratings of the Province of Manitoba (the "Province"), as the Utility's debt securities are direct obligations of the Province or are guaranteed by the Province. DBRS placed the Province's long-term rating on a Positive trend on June 21, 2002.

As a regulated utility, Manitoba Hydro generates relatively stable earnings and cash flow year-over-year. Earnings and cash flows have, however, improved substantially over the past two years. This improvement is largely due to the increase in exports sales to the U.S., which has been facilitated by the Utility's coordination agreement with the Midwest Independent System Operator ("MISO"), giving Manitoba Hydro greater access to customers in U.S. markets. Manitoba Hydro benefits from its low-cost hydro-based generation capacity, which provides the Utility with electricity that is extremely competitive in other jurisdictions. Earnings and cash flow volatility have increased largely as a result of its greater participation in the export markets and electricity price fluctuations in the U.S. Manitoba Hydro has recently signed a ten-year power supply contract with NSP Minnesota (a subsidiary of Xcel Energy Inc.), which will replace its existing contract that expires in 2005. This contract will provide for a degree of earnings and cash flow stability for a significant portion of Manitoba Hydro's energy exports.

Synergies gained through the integration of Centra Gas have provided a stable source of accretive earnings. Similar results are expected from the acquisition of Winnipeg Hydro, which closed September 2002.

While Manitoba Hydro continues to generate sufficient operating cash flows to internally fund capital expenditures, distributions payable to the Province of $288 million over the next two years will constrain the Utility's ability to reduce debt. As such, leverage and key financial ratios will remain weak in comparison to investor-owned utilities.

Other factors that will negatively impact cash flow over the mid- to long-term include: (1) a doubling of water rental fees, implemented April 2001; (2) the equalization of northern and rural customer rates to levels charged in Winnipeg; and (3) no rate increases on the horizon to offset the difference.

RATING CONSIDERATIONS

Strengths:

- Debt is guaranteed by the provincial government
- Low-cost hydro-based generation with storage capacity
- Interconnections with U.S., Saskatchewan, and Ontario
- Centra Gas and Winnipeg Hydro acquisitions are expected to improve profitability
- Cash flows sufficient to internally fund capital expenditures

Challenges:

- High debt level weakens most financial ratios
- Earnings are sensitive to hydrologic conditions
- Earnings somewhat sensitive to exchange rates
- Domestic energy rates have not increased since 1997
- One NFA First Nation claim has not been settled

FINANCIAL INFORMATION

	12 months ended	For years ended March 31					
	June, 30 2002	2002	2001	2000	1999	1998	1997
EBIT interest coverage (times)	1.31	1.39	1.53	1.31	1.19	1.22	1.21
Net debt in capital structure (1)	83.0%	82.9%	85.3%	88.1%	89.5%	90.8%	92.4%
Cash flow/total debt (times)	0.07	0.07	0.08	0.06	0.06	0.06	0.06
Cash flow/capital expenditures (times)	0.94	1.08	1.43	1.15	0.98	1.35	1.03
Net income ($ millions)	176	214	270	152	100	111	101
Operating cash flow ($ millions)	440	474	519	379	325	334	307
Electricity sales (millions of kWh)	-	29,214	28,806	26,688	27,692	29,462	27,567
Electricity revenues (cents per kWh sold)	-	4.70	4.38	4.17	3.88	3.52	3.69
Variable costs (cents per net gen kWh sold)	-	1.13	1.10	1.11	0.94	0.75	0.84
Fixed costs (cents per net gen kWh sold)	-	3.27	2.79	2.93	2.69	2.41	2.50
Average coupon on long-term debt	-	8.17%	8.31%	8.38%	8.56%	8.79%	8.74%

(1) Net of sinking fund assets. Customer contributions excluded from capital structure.

THE COMPANY

The Manitoba Hydro-Electric Board, a wholly owned Crown corporation of the Province of Manitoba, generates, transmits, and distributes electricity in the Province of Manitoba. With the acquisition of the Province's private sector gas distributor, Centra Gas Manitoba in July 1999, Manitoba hydro is now the largest gas distributor in Manitoba.

AUTHORIZED PAPER AMOUNT Limited to US$500 million (includes T-Bills).

New Brunswick Power Corporation

(The rating is a flow-through of the Province of New Brunswick, which conducts all of the Utility's financing activities. This report specifically analyzes the Utility.)

Report Date: October 17, 2002
Press Released: October 15, 2002
Previous Report: September 18, 2001

Matthew Kolodzie, P.Eng./Geneviéve Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Positive	Confirmed	Corporate Long-Term Debt
R-1 (low)	Stable	Confirmed	Corporate Short-Term Debt

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Corporate Long-Term Debt	"A"	"A"	"A"	"A"	"A"	"A"	"A"
Corporate Short-Term Debt	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

RATING UPDATE

The ratings for New Brunswick Power Corporation ("NB Power" or the "Utility") are a flow-through of the ratings of the Province of New Brunswick (the "Province"), which conducts all of the Utility's financing activities. As a regulated utility, NB Power generates relatively stable earnings and cash flow year-over-year. The availability of the 635 MW Point Lepreau nuclear station is the most significant factor that affects earnings and cash flow stability, since the station provides around 25% of the Utility's electricity generation. During periods of plant unavailability, more expensive power purchases are required to replace the electricity that would otherwise be provided by Lepreau. Other factors affecting cash flow stability include fuel prices, temperature, and water flows at the Utility's hydro facilities.

NB Power has consistently generated surplus cash flows, well in excess of maintenance capital expenditures, and is not required to pay dividends to the Province. The surplus has allowed NB Power to reduce debt for the sixth consecutive year in F2002. With annual maintenance capital expenditures in the $100 million to $120 million range and no dividend requirements, NB Power should continue to generate free cash surpluses, as long as the Lepreau nuclear station is operating relatively problem free. Surplus cash can be used to continue reducing net debt levels. Certain major capital projects under development, including the potential refurbishment of Point Lepreau in F2006 ($850 million), could reduce the surplus available for debt reduction. However, it is expected that NB Power will proceed with these projects with third-party equity participation, which would reduce balance sheet pressure. In fact, DBRS expects that it is unlikely that the provincial government would support NB Power in undertaking Point Lepreau without an external partner. Without the refurbishment, closure of Point Lepreau would be required some time between 2007 and 2010, which would pressure cash flow and affect the Utility's ability to reduce debt thereafter. Despite continued efforts to reduce debt, the debt to capital ratio remains high at 105%, and interest coverage and cash flow to debt remains relatively weak for a regulated utility.

NB Power is well positioned geographically to wheel and/or export electricity to the U.S. northeast. However, current high oil prices makes the Utility's export power less competitive in the U.S. northeast. Competitive pressures are expected to develop over the longer term in both domestic and export markets, as the gas distribution networks expand.

Restructuring of the New Brunswick electricity market is scheduled for April 1, 2003.

RATING CONSIDERATIONS

Strengths:

- Debt guaranteed by provincial government
- Well-positioned geographically to wheel/export power to U.S.
- Surplus cash flows available for debt reduction
- Fuel source conversions will reduce costs and emissions
- Restructuring will allow for risk sharing

Challenges:

- Operating difficulties with Lepreau nuclear generator
- Excessively high debt levels, weak profitability
- Foreign exchange exposure
- Sable Island gas a growing competitive threat
- Wholesale competition begins in April 2003

FINANCIAL INFORMATION

For years ended March 31	2002	2001	2000	1999	1998	1997
EBIT interest coverage (times)	1.20	1.10	1.10	1.11	0.91	0.79
Net debt in capital structure	105.2%	105.8%	103.0%	105.0%	91.3%	88.3%
Cash flow/total debt (times)	0.08	0.07	0.08	0.08	0.05	0.04
Cash flow/capital expenditures (times)	1.67	1.81	2.49	3.68	2.61	1.72
Net income (before transfers/extras.) ($ millions)	39	(66)	73	(25)	(53)	(83)
Operating cash flow ($ millions)	234	214	237	239	154	119
Electricity sales (millions of kWhs)	19,059	18,889	19,842	20,597	18,577	16,805
Electricity revenues (cents per kWh sold)	6.71	6.69	6.14	5.71	5.99	5.99
Variable costs (cents per net gen kWh sold)	3.94	4.02	3.26	2.89	3.27	3.35
Fixed costs (cents per net gen kWh sold)	2.87	3.48	3.20	3.30	3.56	4.19
Average coupon on long-term debt	8.06%	8.39%	8.88%	9.07%	9.06%	9.07%

THE COMPANY

New Brunswick Power Corporation, a wholly owned Crown corporation of the Province of New Brunswick, generates, transmits, and distributes electricity in the province of New Brunswick. By April 1, 2003, NB Power will be restructured into NB Power Holding Company with four separate operating subsidiaries: (1) a generation company, (2) a nuclear company, (3) a transmission company, and (4) a distribution/customer service company.

ORDER-IN-COUNCIL LIMIT No specified limit. All financing activities are conducted through the provincial government.

Newfoundland and Labrador Hydro

(The rating is based on the Provincial guarantee. This report specifically analyzes Newfoundland and Labrador Hydro.)

Current Report: July 30, 2002
Previous Report: October 2, 2001

Geneviève Lavallée, CFA / Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
BBB	Stable	Confirmed	Long-Term Debt
R-2 (high)	Stable	Confirmed	Commercial Paper/Treasury bills

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Long-Term Debt	BBB	BBB	BBB	BBB	BBB	BBB (low)	BBB (low)
Commercial Paper/Treasury bills	R-2 (high)	R-2 (high)	R-2 (high)	R-2 (high)	R-2 (high)	R-2 (middle)	R-2 (middle)

UPDATE

Newfoundland and Labrador Hydro's ("the Utility") rating is a flow-through of the rating of the Province of Newfoundland and Labrador ("the Province"), which unconditionally guarantees the Utility's debt. The Utility's net earnings rebounded sharply in 2001 as a result of the favourable re-negotiation of the three-year recall agreement with Hydro-Québec. Despite the higher net earnings, operating cash flow weakened significantly due to the sharp increase in the rate stabilization plan as a result of the significant cost variances in 2001 between actual fuel prices and the base price. Prior to 2002, rates were set based on an oil price of Cdn$12.5/barrel, with the difference between the base prices and actual price (currently around Cdn$25/barrel) recovered through rates over the following three-year period. The reduced operating cash flows, combined with the high dividend payments and high capital expenditures, resulted in another free cash flow deficit, which was financed with debt. The Utility's leverage and cash flow/debt ratio deteriorated further in 2001, while EBIT interest coverage recovered somewhat from its sharp decline in 2000.

The medium-term outlook for the Utility's financial profile remains reasonable. Net income is expected to remain stable or post modest growth, while operating cash flows should improve significantly (and be less volatile) as a result of some of the recent regulatory decisions, namely, the annual re-basing of fuel costs based on forecast fuel prices. Despite the projected improvement in cash flows, the Utility will continue to post free cash flow deficits in the short term due to the major capital projects currently underway and the substantial projected dividend payment to the Province in 2002. As a result, leverage will increase and key financial ratios are expected to remain weak. Over the medium term, the Utility's financial profile is expected to remain weaker relative to comparable investor-owned utilities.

Over the long term, the key challenges facing the Utility include the ongoing sensitivity of cash flows to water levels and fuel prices, although the volatility has been significantly reduced due to recent regulatory decisions. Its financial profile could also be negatively impacted if the proposed large Labrador projects go ahead, depending on the form of the Utility's participation. The Utility's competitiveness could also be negatively impacted by any future environmental issues associated with the high sulphur content of Bunker C fuel.

CONSIDERATIONS

Strengths:

- Debt is unconditionally guaranteed by the Province
- New regulatory environment – rate of return basis
- Two-thirds interest in Churchill Falls
- Geographic isolation and unavailability of gas minimizes competitive pressures, impact of industry deregulation
- Rate Stabilization Plan contributes to long-term earnings stability

Challenges:

- Cash flows sensitive to water levels and oil prices
- High realized foreign exchange losses
- Large Labrador projects could pressure key debt ratios should construction commence
- Environmental issues related to sulphur content of Bunker C fuel

FINANCIAL INFORMATION

	For the years ended December 31					
	2001	2000	1999	1998	1997	1996
EBIT interest coverage (times)	1.39	1.17	1.51	1.45	1.24	1.17
% net debt in capital structure (1)	68.2%	66.4%	63.1%	65.2%	68.1%	69.4%
Cash flow/total net debt (times) (1)	0.03	0.06	0.11	0.09	0.06	0.04
Cash flow/capital expenditures (times) (1)	0.39	1.33	1.97	3.11	2.30	1.61
Net income (bef. extras.) ($ millions)	53	35	68	70	43	29
Operating cash flow ($ millions)	32	62	111	86	58	39
Electricity sales (millions of kWhs)	8,341	8,206	7,988	7,598	6,781	6,589
Electricity revenues (cents per kWh sold)	3.88	3.68	3.96	3.98	4.30	4.35
Variable costs (cents per net gen kWh sold)	2.40	2.35	2.17	2.04	2.02	2.10
Fixed costs (cents per net gen kWh sold)	2.10	2.25	2.33	2.46	2.32	2.46
Avg. coupon on long-term debt	8.07%	8.40%	8.38%	8.73%	9.51%	10.10%

(1) Cash flows include dividends received, debt is net of sinking fund assets.

THE COMPANY

Newfoundland and Labrador Hydro, a Crown corporation of the Province of Newfoundland and Labrador, generates and transmits electricity in Newfoundland and Labrador. The Utility sells about 65% of its output to a private sector electricity distributor, Newfoundland Power Inc., and distributes the remainder to rural customers and a small group of industrial companies.

AUTHORIZED PAPER AMOUNT (ORDER-IN-COUNCIL LIMIT) Cdn$300 million

Newfoundland Power Inc.

Report Date: January 31, 2003
Press Released: January 30, 2003
Previous Report: January 9, 2002

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	First Mortgage Bonds
Pfd-2	Stable	Confirmed	Preferred Shares – cumulative, redeemable

Matthew Kolodzie, CFA / Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING HISTORY	Current	2002	2001	2000	1999	1998	1997
First Mortgage Bonds	"A"	"A"	"A"	"A"	"A"	"A"	"A"
Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

RATING UPDATE

DBRS is confirming the long-term debt rating of Newfoundland Power Inc. ("Newfoundland Power" or the "Company") as noted. Newfoundland Power's key strength is its regulated electricity transmission and distribution operations, which provide a favourable degree of stability to earnings and cash flow. Key strengths of current regulation include: (1) an automatic adjustment formula to help reduce earnings sensitivity to interest rate fluctuations, (2) a rate stabilization account to absorb fluctuations between estimated and actual cost of fuel oil to the Company's primary electricity supplier, (3) a weather normalization account to stabilize earnings during extreme weather conditions, and (4) a favourable approved equity of 45% that contributes to the Company's strong financial profile.

Earnings growth is expected be moderate over the near term, with (1) a sales growth rate in the 1% to 1.5% range, (2) continued efforts to reduce operating costs, and (3) a proposed distribution rate increase in May 2003. Annual capital expenditures are expected to be in the $55 million to $60 million range as the Company continues with upgrades to improve system reliability and efficiency. Free cash flows will likely remain slightly negative over the medium term and lead to a modest increase in debt. However, retained earnings are expected to be sufficient to maintain debt-to-capitalization near the deemed amount of 55%. As such, the Company's financial profile and interest coverage ratios will remain stable.

The Company's key challenges include: (1) reliance on purchased power from Newfoundland and Labrador Hydro ("NLH," over 90% of power requirements), and purchased power costs are highly influenced by the price of oil; (2) a relatively low level of demand growth in Newfoundland, which limits earnings growth potential; and (3) high coupon debt, which adversely impacts cash flows and coverage ratios.

The Newfoundland and Labrador provincial government is currently in the process of reviewing submissions on its proposed Energy Policy. However, it is unlikely that any meaningful changes will be enacted until after the next provincial election, which must be called by February 2004.

RATING CONSIDERATIONS

Strengths:
- Regulation contributes to earnings/financial stability
- Weather normalization account reduces short-term earnings volatility
- Relatively strong balance sheet and favourable financial profile
- Geographic isolation limits competitive pressures

Challenges:
- Reliance on Newfoundland and Labrador Hydro for majority of power supplied (heavily influenced by the cost of oil)
- Earnings constrained by low ROE, dependent on interest rates
- High coupon debt issues and early redemption penalized
- Low electricity demand growth

FINANCIAL INFORMATION

	12 mos. ended	For years ended December 31				
	Sept. 2002	2001	2000	1999	1998	1997
Fixed-charges coverage (times)	2.65	2.60	2.47	2.39	2.33	2.72
% adjusted debt in capital structure (1)	54.8%	56.2%	54.0%	55.0%	55.5%	53.7%
Cash flow/total adjusted debt (times) (1)	0.18	0.20	0.19	0.16	0.16	0.18
Cash flow/capital expenditures (times)	1.16	1.77	1.36	1.19	1.09	1.73
Net income ($ millions) (bef. extras., after pfd. div.)	28.6	30.9	28.5	23.4	21.6	28.1
Operating cash flows ($ millions) (after pfd. div.)	61.1	68.6	56.9	50.4	48.5	49.8
Electricity sold (GWh)	-	4,667	4,555	4,500	4,440	4,438
Approved ROE	9.05%	9.59%	9.59%	9.25%	9.25%	11.00%
Average coupon on long-term debt	9.56%	9.56%	9.66%	9.66%	9.66%	10.26%

THE COMPANY

Newfoundland Power Inc. transmits and distributes electricity to approximately 220,000 customers throughout the island of Newfoundland. The Company purchases over 90% of its electricity needs from government-owned Newfoundland and Labrador Hydro and generates the balance from owned generation facilities (148 MW). Fortis Inc. ("Fortis," see separate report) owns all the common shares of Newfoundland Power Inc.

Nova Scotia Power Inc.

Report Date: November 28, 2002
Press Released: November 20, 2002
Previous Report: May 25, 2001

Matthew Kolodzie, CFA/Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (low)	Stable	Confirmed	Unsecured Debentures & Medium Term Notes
A (low)	Stable	Confirmed	Government guaranteed debt (issued prior to June 1992)
Pfd-2 (low)	Stable	Confirmed	Cumulative Preferred Shares

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Long-Term Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)*	Pfd-2	Pfd-2

* On October 1, 1998, DBRS broadened its preferred share rating scale, resulting in technical changes to the Utility's preferred share rating.

RATING UPDATE

DBRS is confirming the ratings for Nova Scotia Power Inc. ("Nova Scotia Power" or the "Company") as noted above, following a review of the impact of the recent ruling by the Nova Scotia Utilities and Review Board ("UARB") on the Company's 2002 rate application. The ruling has granted Nova Scotia Power an average rate increase of 3.3% beginning November 1, 2002. This is Nova Scotia Power's first-rate increase since 1996, and will assist the Company in offsetting increasing operating costs (such as higher unit fuel costs). However, the significant time lag in receiving the UARB's ruling will lead to weaker earnings in 2002. In addition, Nova Scotia Power recently withdrew its 2003 rate application, which would have requested a pass-through of the increase in municipal property taxes and corporate income taxes expected in 2003. The impact of this tax increase will, however, be manageable in 2003, with increased revenues from higher rates and favourable load growth in the Province of Nova Scotia (the "Province"). Tax increases will likely be addressed in the Company's 2004 rate application, which is expected to be filed in mid-2003.

The rating continues to be supported by (1) the Company's ability to generate relatively stable cash flows, which are well in excess of internal needs; and (2) a regulated capital structure, which ensures that the debt to equity ratio remains stable, reflecting a 35% deemed equity (UARB treats preferred shares as debt), and the UARB will allow Nova Scotia Power to increase its equity to up to 40%. Nova Scotia Power's financial flexibility will improve with an equity injection from its parent, Emera Inc., later this year.

Escalating fuel costs and a growing tax burden will continue to be a challenge for the Company to manage. Under cost of service regulation, these costs are normally passed through to customers, but material time lags in receiving regulatory decisions (which are not retroactive) will continue to pressure earnings over the near to medium term. The filing of rate applications on a more frequent basis will enhance earnings stability over the longer term and should improve Nova Scotia Power's relationship with the UARB. In addition, tightening of emission standards on coal-based generation (over 75% of the Company's throughput in 2001) could lead to potentially expensive capital investment over the longer term.

RATING CONSIDERATIONS

Strengths:

- Regulated operations contribute to earnings and cash flow stability
- Material surplus cash flows for foreseeable future
- Geographic isolation and limited interconnections are effective barriers against external competitors
- Opportunity to export surplus power

Challenges:

- Competitive pressures: gas distribution network under development, electricity industry deregulation
- Regulatory risks
- High-cost generator/low population density of franchise
- Earnings sensitive to weather and commodity prices
- Future environmental risks: coal-based plants

FINANCIAL INFORMATION

	12 mos. ended	Years ended December 31				
	Sept. 2002	2001	2000	1999	1998	1997
Fixed-charges coverage (times)	1.87	1.94	1.97	1.93	1.78	1.82
Adjusted debt in capital structure (1)	57.9%	59.1%	59.0%	59.9%	62.2%	62.8%
Cash flow/adjust. total debt (times) (1)	0.13	0.13	0.15	0.14	0.13	0.13
Cash flow/capital expenditures (times)	1.68	1.89	1.98	2.07	1.70	2.23
EBIT ($ millions)	241.7	258.8	254.5	254.4	238.7	252.6
Net income (after pfd. divs.) ($ millions)	87.1	105.1	103.7	103.2	85.5	92.7
Operating cash flow ($ millions)	206.0	211.5	240.5	236.3	223.5	223.9
Electricity sales (GWh)	10,981	10,906	10,656	10,365	9,772	9,516

(1) Preferred shares treated as 30% debt equivalents.

THE COMPANY

Nova Scotia Power Inc. generates, transmits, and distributes electricity in the Province of Nova Scotia. The Utility is wholly owned by Emera Inc., which is a widely held company listed on the Toronto Stock Exchange.

AUTHORIZED COMMERCIAL PAPER AMOUNT Limited to $350 million, 100% secured with a backup line of credit.

Press Release

Dominion Bond Rating Service Limited

Energy

Date of Release: December 11, 2002

DBRS Confirms Ontario Power Generation Inc. at A (low) & R-1 (low), Long-Term Trend Still Negative

Geneviève Lavallée, CFA; Matthew Kolodzie, CFA / 416-593-5577 ext.2277, ext.2296 / glavallee@dbrs.com

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (low)	Negative	Confirmed	Unsecured Debt

Note: Ontario Power Generation does not currently have outstanding any unsecured debentures issued in its own name.

The ratings on Ontario Power Generation Inc.'s ("OPG" of the "Company") commercial paper and senior, unsecured debentures are confirmed at R-1 (low) and A (low), respectively. The long-term trend remains Negative and the short-term trend remains Stable. The ratings were placed "Under Review with Negative Implications" on November 12, 2002, following the plan announced by the Ontario government on November 11, 2002 to lower electricity bills.

The rating confirmation reflects a review of the recent actions by the provincial government and the recently passed legislation in respect of the Ontario electricity market. DBRS is of the view that the recently passed legislation will have little direct impact on OPG's credit profile, as the provincial government has not imposed restrictions on the wholesale generation market. The financially burdensome measures implemented by the Province apply only to transmission, distribution, and retail.

The long-term trend was changed to Negative on October 31, 2002, due to the following factors: (1) further delays and cost overruns on the return to service of Pickering A Unit 4, and the uncertainty as to when the Company will continue with the restoration of all or some of the remaining three units of Pickering A once Unit 4 is fully operational; (2) the uncertainty surrounding the Ontario Energy Board's approval of the requested reduction in the level of OPG's market power mitigation rebates to account for the sales of the Bruce Nuclear Plant and the Mississagi hydro plants; and (3) OPG's high exposure to political interference. These factors continue to exist. A downgrade may be warranted if the outcome of the above-mentioned factors results in a deterioration in OPG's operating performance and financial profile.

OPG's current ratings remain supported by the following factors: (1) OPG is a relatively low-cost producer, (2) the average price of electricity in Ontario is not expected to fall much below $40/MWh over the medium term, and (3) earnings and cash flows are expected to improve substantially once Pickering A Unit 4 becomes fully operational.

Dominion Bond Rating Service Limited (DBRS) will publish a full report shortly that will provide additional analytical detail on this rating action. If you are interested in receiving this report, please contact us at: info@dbrs.com.

Ontario Power Generation Inc.

Report Date: December 18, 2002
Press Released: December 11, 2002
Previous Report: May 31, 2002
Geneviève Lavallée, CFA/Matthew Kolodzie, CFA
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
A (low)	Negative	Confirmed	Senior, Unsecured Debt*

RATING HISTORY

	Current	2001	2000	1999	1998	1997
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	NR	NR	NR
Senior, Unsecured Debt*	A (low)	"A"	"A"	NR	NR	NR

* Ontario Power Generation Inc. does not currently have outstanding any unsecured debentures issued in its own name.

RATING UPDATE

The ratings on Ontario Power Generation Inc.'s ("OPG" or the "Company") commercial paper and senior, unsecured debentures are confirmed at R-1 (low) and A (low), respectively. The long-term trend remains Negative and the short-term trend remains Stable.

The rating confirmation reflects a review of the recent actions by the provincial government and the recently passed legislation in respect of the Ontario electricity market. DBRS is of the view that the recently-passed legislation will have little direct impact on OPG's credit profile, as the provincial government has not imposed restrictions on the wholesale market. The financially burdensome measures implemented by the Province apply only to transmission, distribution, and retail. The long-term trend was changed to Negative on October 31, 2002 due to the following factors: (1) Further delays and cost overruns on the return to service of Pickering A Unit 4, and the uncertainty as to when the Company will continue with the restoration of all or some of the remaining three units of Pickering A once Unit 4 is fully operational; (2) The uncertainty surrounding the Ontario Energy Board's ("OEB") approval of the requested reduction in the level of OPG's market power mitigation rebates to account for the lease of the Bruce Nuclear Plant and the sale of the Mississagi hydro plants; and (3) OPG's high exposure to political interference. These factors continue to exist. A downgrade may be warranted if the outcome of the above-mentioned factors result in a deterioration in OPG's operating performance and financial profile.

OPG's current ratings remain supported by the following: (1) OPG is a relatively low-cost producer; (2) the average price of electricity in Ontario is not expected to fall much below $40/MWh over the medium term; (3) earnings and cash flows expected to improve substantially once Pickering A Unit 4 becomes fully operational.

RATING CONSIDERATIONS

Strengths:

- Low-cost power producer
- Strong market position in Ontario
- Good energy trading position
- Limited nuclear liability
- Earnings and operating cash flows expected to rise over longer term

Challenges:

- Uncertainty related to operating environment
- Significant delays and cost over-runs on Pickering A project
- Leverage projected to rise to 50%
- Lack of access to equity markets
- Increasing proportion of nuclear generation

FINANCIAL INFORMATION

	12 mos. ending	For years ended December 31 (1)		
	Sept. 2002	2001	2000	1999
Fixed-charges coverage (times)	1.37	2.13	6.41	4.88
% gross debt in capital structure	38.3%	37.1%	38.6%	38.7%
Cash flow-n.w.f.*/total gross debt (times)	0.45	0.51	0.51	0.49
Cash flow/capital expenditures (times)	1.20	1.56	2.36	2.06
Net income bef. extras ($ millions)**	63	152	490	437
Operating cash flow ($ millions)**	1,041	1,154	1,383	1,326
Electricity sales - billion of kWh	128.8	140.2	139.8	136.9
Variable costs (cents per net gen kWh sold)(2)	3.39	3.35	2.73	2.68
Fixed cost (cents per net gen kWh sold)	0.99	0.90	0.92	0.96
Average coupon on long-term debt	5.97%	5.97%	5.93%	5.93%

(1) 1999 consists of 9 months. OPG + 3 months proforma allocation/DBRS estimates of Ontario Hydro results.
(2) Excludes income taxes. * n.w.f.: nuclear waste funding ** DBRS adjusted

THE COMPANY

Ontario Power Generation Inc. is one of the successor companies of the former Ontario Hydro, with a diverse portfolio of 22,169 MW of installed in-service generating capacity (plus 2,060 MW of laid-up generation capacity at Pickering A). The Company is wholly owned by the Province of Ontario. Debt issued directly by Ontario Power Generation Inc. is not guaranteed by the Province.

AUTHORIZED PAPER AMOUNT Limited to Cdn$1 billion

Current Report: October 10, 2002
Previous Report: September 4, 2001

Saskatchewan Power Corporation*

*The rating is a flow-through of the Province of Saskatchewan, which conducts most of Saskatchewan Power's financing activities
This report specifically analyzes Saskatchewan Power.

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Corporate Long-Term Debt
R-1 (low)	Stable	Confirmed	Corporate Short-Term Debt

Matthew Kolodzie, P.Eng./ Geneviéve Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING HISTORY

	Current	2001	2000	1999	1998	1997	1996	1995
Corporate Long-Term Debt	"A"	"A"	"A"	A (low)	A (low)	A (low)	BBB (high)	BBB high)
Corporate Short-Term Debt	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-2 (high)	R-2 (high)

RATING UPDATE

Saskatchewan Power Corporation's ("SaskPower" or the "Utility") ratings are a flow-through of the ratings of the Province of Saskatchewan (the "Province"), as the Utility's securities are direct obligations of the Province. As a regulated utility, SaskPower generates relatively stable earnings and cash flow year-over-year. However, extremely poor hydrological conditions and high natural gas prices resulted in a significant drop in earnings in 2001. Earnings are expected to return to more historical levels in 2002 with hydrologic conditions returning to normal and lower gas prices. Leverage has increased to 59% of capitalization, mainly as a result of financing two key capacity expansion projects (1) re-powering of the 150 MW Queen Elizabeth Power Station and (2) the 228 MW Cory Cogeneration project. With these projects, SaskPower will have sufficient generating capacity to accommodate load growth in Saskatchewan for the next seven to ten years.

SaskPower has good financial flexibility with one of the strongest balance sheets among government-owned utilities in Canada, and is within the range of investor-owned utilities. While coverage ratios and cash flow to debt weakened in 2001 due to the drop in cash flow, these key ratios remain adequate for a predominately regulated utility, and are expected to return to historical levels in 2002.

SaskPower operates in a relatively favourable regulatory environment, with a rate of return on equity of 10% and a rate review process that typically takes only 90 days. The Utility has recently implemented two system-wide rate increases (April 2001 and January 2002) and is considering a possible rate increase in 2003. With these rate increases and a return to more normal hydrologic conditions, it is expected that operating cash flows will be sufficient to internally fund planned annual capital expenditures in the $300 million to the $350 million range over the medium term. A significant portion of these expenditures will be to refurbish the Utility's aging infrastructure.

In addition to hydrologic conditions, key factors that have added to earnings volatility include: (1) natural gas prices, which will become more significant as SaskPower increases its gas-fired generation base; and (2) fluctuations in the U.S. dollar/Canadian dollar exchange rate, which has become more significant with the adoption of new CICA standards that require the recognition of foreign currency translation differences immediately on the income statement (roughly half of SaskPower's debt is denominated in U.S. dollars). Hedging policies have been introduced to mitigate the earnings volatility associated with these two factors.

RATING CONSIDERATIONS

Strengths:

- Debt securities are direct obligations of the Province
- Favourable regulatory environment
- Limited interconnections reduce competitive pressures
- Relatively strong balance sheet
- Key customers locked into long-term power purchase contracts
- Capacity expansion to address growing power needs

Challenges:

- High variable costs
- Aging infrastructure requires significant capital investment
- A high proportion of industrial customers increases earnings sensitivity to economic cycles
- High foreign exchange exposure
- Environmental issues surrounding coal-based generation

FINANCIAL INFORMATION

	12 months ended	For years ended December 31				
	June 2002	2001	2000	1999	1998	1997
EBIT interest coverage (times)	1.59	1.39	1.85	1.71	1.79	1.70
Net debt in the capital structure	59.0%	60.0%	57.4%	57.8%	62.3%	62.6%
Cash flow/total debt (times)	0.15	0.13	0.18	0.17	0.18	0.18
Cash flow/capital expenditures (times)	1.18	1.08	1.59	1.47	2.28	2.22
Net income ($ millions)	106	29	108	174	94	108
Operating cash flow ($ millions)	256	219	274	256	285	295
Electricity sales (millions of kWhs)	-	16,900	17,049	16,225	16,187	15,608
Electricity revenues (cents per kWh sold)	-	6.66	6.33	5.90	5.81	5.78
Variable costs (cents per net gen kWh sold)	-	4.55	4.01	3.13	2.71	2.48
Fixed costs (cents per net gen kWh sold)	-	2.99	2.63	2.00	2.79	2.86
Average coupon on long-term debt	-	8.66%	8.95%	9.11%	9.20%	9.34%

THE COMPANY

Saskatchewan Power Corporation, a Crown corporation of the Province of Saskatchewan, generates, transmits, and distributes electricity in Saskatchewan.

ORDER-IN-COUNCIL LIMIT All financing activities are conducted through the provincial government.

Press Release

Dominion Bond Rating Service Limited

Date of Release: January 31, 2003

Energy

DBRS Downgrades Toronto Hydro Corporation to A (low), Confirms at R-1 (low), Ratings Remain "Under Review with Negative Implications"

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Under Review – Negative	Commercial Paper
A (low)	Stable	Under Review – Negative	Corporate Rating

DBRS is downgrading the corporate rating on Toronto Hydro Corporation ("Toronto Hydro" or the "Company") to A (low) from "A" and confirming the commercial paper rating at R-1 (low), both with a Stable trend. Both ratings remain "Under Review with Negative Implications," where they were placed on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Toronto Hydro and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity, as such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Toronto Hydro had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

The ratings will remain "Under Review with Negative Implications" until the Toronto municipal council votes on the resolution to declare whether Toronto Hydro will: (1) remain as a commercial entity, as it has been since first incorporating in 1999; or (2) revert back to being a not-for-profit entity. Should Toronto Hydro revert back to being a not-for-profit entity (earning a zero return on equity), a further downgrade would be warranted, as the Company's financial profile would become significantly weaker. Remaining as a commercial entity would warrant the removal of "Under Review with Negative Implications" status.

The Toronto City Council is expected to vote on the resolution by February 5, 2003. If Council does not make a decision on the resolution by March 9, 2003, Toronto Hydro will automatically revert back to being a not-for-profit entity, as defined in Bill 210.

Toronto Hydro's rating continues to be supported by the following factors: (1) a favourable franchise area; (2) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; and (3) a strong supportive parent, the City of Toronto. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Toronto Hydro's rating report will follow the release of the Company's 2002 financial statements.

Toronto Hydro Corporation

RATING

Current Report: February 21, 2002
Matthew Kolodzie, P.Eng., Geneviève Lavallée, CFA
416-593-5577 ext. 2296/ext. 2277
mkolodzie@dbrs.com

Rating	Trend	Rating Action	Debt Rated
A	Stable	New Rating	Corporate Rating
R-1 (low)	Stable	New Rating	Commercial Paper

RATING HISTORY	2002	2001	2000	1999	1998	1997
Corporate Rating	A	NR	NR	NR	NR	NR
Commercial Paper	R-1 (low)	NR	NR	NR	NR	NR

COMMENTARY

New ratings have been assigned to Toronto Hydro Corporation ("Toronto Hydro" or "the Company"). The following key factors support the ratings: (1) A high level of earnings stability supported by its regulated distribution business; (2) A favourable franchise area with high-density population, thus lower average operating costs per customer; (3) An improved regulatory environment in Ontario, which allows for higher rates charged to customers, performance-based earnings incentives as operating efficiency improves, and a pass-through of extraordinary expenses; and (4) A financially strong parent, the City of Toronto.

The most significant challenges facing Toronto Hydro surround the many changes the Company is undergoing as it restructures to meet the requirements of the new Ontario electricity market. (1) The Company is experiencing a substantial change in its corporate culture as it evolves into a profit-oriented organization from its previous highly-regulated and bureaucratic structure. This has involved significant management changes and a 32% staff reduction over a short time period. (2) Distribution rates are currently below those required to earn the allowed rate of return. Distribution rate increases will be phased in over a three-year period (2001-2004) to achieve the returns allowed by the regulator. An unexpected increase in operating costs or reduced demand brought on by a severe economic downturn or unusual weather patterns will have a negative effect on profitability. (3) The allowable return on equity is low, at 9.88%, relative to similar companies in the U.S. (4) Financial flexibility is limited by the Company's inability to issue common equity (its equity base is limited to internal earnings growth). (5) Diversification beyond regulated distribution will increase business risk, although the proportion of earnings from un-regulated businesses remains low at less than 10%, and is unlikely to exceed 20% in the medium term.

The Toronto Hydro service area is noted for its stability in electricity demand, as sales have ranged between 24.6 billion kWh to 25.8 billion kWh from 1990 to present. Also, close to 90% of its customers are residential and small/medium-sized commercial, who are less sensitive to economic cycles than large commercial and industrial customers. These factors, along with over 90% of earnings coming from regulated distribution, should result in relatively stable earnings going forward. Furthermore, the rating is supported by the Company's commitment to maintaining leverage in the 60%-65% range and sustaining adequate coverage.

RATING CONSIDERATIONS

Strengths:

- High level of earnings stability
- Favourable franchise area with high density population
- Improved regulatory environment
- Financially strong parent
- Strong brand name

Challenges:

- Change in corporate culture
- Low regulatory returns
- Distribution rate increases are being phased in over 3 years
- Diversifying beyond regulated transmission & distribution
- Lack of access to public equity markets

FINANCIAL INFORMATION

For the years ending Dec. 31; 1995-7 reflect Jan. 1998 amalgamation

	2001	2000	1999	1998R	1997R	1996R
Fixed-charges coverage (times)	1.57	0.82	6.04	8.22	7.81	14.68
Percent debt in capital structure	62.8%	63.6%	63.1%	4.4%	5.0%	4.1%
Cash flow/total debt (times)	0.12	0.11	0.12	1.92	1.58	2.25
Cash flow/capital expenditures (times)	0.77	0.63	0.77	1.10	0.91	0.98
EBIT ($ millions)	67.3	27.9	20.1	56.1	53.9	73.9
Pre-tax income (bef extra.) ($ millions)	24.0	(6.1)	16.7	49.1	46.9	68.7
Operating cash flow ($ millions)	126.9	104.8	122.2	146.6	137.6	153.3
EBIT margin	18.7%	8.8%	6.5%	18.0%	17.2%	22.5%
Return on average equity	4.1%	-1.1%	1.5%	2.9%	2.9%	4.4%
Electricity throughputs (GWh)	25,722	25,422	25,339	24,718	24,804	24,656
Customer base	660,946	656,962	657,782	656,340	655,790	652,089

R = Revised to exclude equity in Ontario Hydro.

THE COMPANY

Toronto Hydro Corporation is a holding company with the following subsidiaries: Toronto Hydro-Electric System Ltd. ("THESL"), regulated electricity distributor; Toronto Hydro Energy Service Inc. ("THESI"), unregulated wholesaler and retailer of electricity, natural gas, and other energy services; Toronto Hydro Telecom Inc., fibre-optic leasing; and 1455948 Ontario Inc., a clearing company. THESL represents the consolidation of former Toronto, Etobicoke, North York, Scarborough, York and East York distribution systems.

Press Release

Dominion Bond Rating Service Limited

Date of Release: January 24, 2003 Energy

DBRS Confirms TransAlta Corporation at BBB (high), R-1 (low) & Pfd-3 (high)y, Trends Now Negative

Geneviève Lavallée; CFA; Matthew Kolodzie, CFA / 416-593-5577 ext.2277, ext.2296 / glavallee@dbrs.com

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Negative	Trend Change	Commercial Paper
BBB (high)	Negative	Trend Change	Unsecured Debentures/Medium-Term Notes
Pfd-3 (high)y	Negative	Trend Change	Preferred Securities, cumulative redeemable

y: denotes hybrid security

The ratings on TransAlta Corporation's ("TAC" or the "Company") unsecured debentures and medium-term notes, preferred securities, and commercial paper are confirmed at BBB (high), Pfd-3 (high)y, and R-1 (low), respectively. All trends are changed to Negative from Stable.

The trend change reflects the increase in TAC's risk profile and the pressure on its financial profile as a result of the announcement to acquire El Paso's 50% interest in CE Generation LLC (CE Generation) for approximately US$240 million (including working capital). CE Generation has non-recourse debt of which TAC's notional 50% share is approximately US$430 million.

The Company's announcement to acquire El Paso's 50% interest in CE Generation increases TAC's risk profile due to the characteristics of the underlying assets. TAC continues to have a target capital structure of 50% debt, excluding non-recourse debt. CE Generation is viewed by DBRS as a higher-risk investment given the current characteristics of the underlying contracts, the counterparties, and the markets within which the plants are located. In its assessment, DBRS has recognized that this investment will be immediately accretive to earnings and cash flows, and that it provides TAC with longer-term benefits through the diversification of its fuel and the geographic market mix of its assets.

Further rating action may be taken if TAC's current financial position does not improve sufficiently over the next 12 to 18 months to compensate for the increased risk profile.

TransAlta Utilities Corporation is unaffected by this acquisition.

Press Release

Dominion Bond Rating Service Limited

Energy

Date of Release: December 12, 2002

DBRS Downgrades TransAlta Corporation to BBB (high) & Pfd-3 (high)y, Short-Term Rating Confirmed at R-1 (low)

Geneviève Lavallée, CFA; Matthew Kolodzie, CFA / 416-593-5577 ext.2277, ext.2296 / glavallee@dbrs.com

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper
BBB (high)	Stable	Downgraded	Unsecured Debt/Medium-Term Notes
Pfd-3 (high)y	Stable	Downgraded	Preferred Securities, cumulative redeemable

y: denotes hybrid security

The ratings on TransAlta Corporation's ("TAC" or the "Company") unsecured debentures and medium-term notes and on its preferred securities are downgraded to BBB (high) and Pfd-3 (high)y, respectively. The rating on TAC's commercial paper is confirmed at R-1 (low). The trends on all ratings are Stable.
The downgrade reflects the recent announcements regarding the Q4 2002 financial results, which will result in a further deterioration in the Company's financial profile since the long-term trends were changed to Negative in October 2002.

The Company recently announced that its Q4 2002 financial results will include a number of charges having a pre-tax impact on earnings of approximately $170 million. The most important of these charges as they relate to the Company's long-term outlook is the pre-tax write-down of $110 million related to the phased decommissioning of its Wabamum facility. TAC has shut down its 150 MW Wabamum Unit 3 effective November 29, 2002. The write-down includes a provision for replacing the power as would be required by the Power Purchase Arrangements (PPA). The Company also announced that Wabamum Units 1 & 2 (132 MW total) will be retired during Q1 2004, following the expiration of the PPA at the end of 2003. The 304 MW Unit 4 will continue to operate until the end of its licence in 2010. The write-down provides further evidence of TAC's higher risk profile due to its small size and the degree to which the Company is impacted financially by operational problems.

TAC continues to face a number of challenges over the next two to three years, which could limit any improvements in its current financial position and potentially result in further rating actions. Electricity prices in Alberta and the northwest U.S. are expected to remain generally lower over the near term. This will dampen any incentive payments received from the plants subject to PPAs in Alberta, and it will negatively impact the earnings and cash flow contributions from the uncontracted portion of the Company's gas-fired power plants, especially if spark spreads remain low. Furthermore, acquisition risk remains high given the Company's publicly-announced intention of taking advantage of selective growth opportunities.

Credit Rating Report

TransAlta Corporation

Report Date: October 31, 2002
Press Released: October 24, 2002
Previous Report: October 25, 2001

Geneviève Lavallée, CFA / Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
A (low)	Negative	Trend Change	Unsecured Debentures & Medium-Term Notes
Pfd-2 (low)y	Negative	Trend Change	Preferred Securities, cumulative redeemable
R-1 (low)	Stable	Confirmed	Commercial Paper

RATING HISTORY

RATING HISTORY	Current	2001	2000	1999	1998	1997	1996
Unsecured Debentures & MTNs	A (low)	A (low)	"A"	A (high)	NR	NR	NR
Preferred Securities	Pfd-2 (low)y	Pfd-2 (low)y	Pfd-2y	Pfd-2 (high)y	NR	NR	NR
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (middle)	NR	NR	NR

y - denotes hybrid security

RATING UPDATE

The ratings on TransAlta Corporation's ("TAC" or the "Company") unsecured debentures and medium-term notes and on its preferred securities are confirmed at A (low) and Pfd-2 (low)y. The trends are changed to Negative from Stable. The rating on TAC's commercial paper is confirmed at R-1 (low), with a Stable trend.

The change in the trend to Negative from Stable reflects the negative impact that a variety of factors have had on the Company's financial results for its continuing operations. Certain key financial measures are currently at the bottom end of the range for an A (low)-rated company having TAC's risk profile. If these key financial measures do not improve and the Company's business risk profile remains the same, a downgrade may be warranted.

The Company faces certain challenges over the next two to three years, which could limit any improvements in its current financial position. Electricity prices in Alberta and the northwest U.S. are expected to remain low over the near term. This will dampen any incentive payments received from the plants subject to Power Purchase Arrangements ("PPAs") in Alberta, and it will negatively impact the earnings and cash flow contributions from the uncontracted portion of the Company's gas-fired power plants, especially if spark spreads remain low. In addition, the Company continues to face risks related to its small size relative to other North American generators. As the Company grows and diversifies its generation portfolio, operational risk should decline. In the meantime, however, the financial impact of unplanned outages is magnified due to its small size.

The current rating is supported by the earnings and cash flow stability offered by the Alberta PPAs. In addition, the Company has a low level of committed capital expenditures over the medium term (ranging from $200 million to $600 million/year), which provides a degree of financial flexibility. In terms of potential acquisitions, the Company is committed to financing the acquisitions such that the target capital structure of 50% debt is maintained.

RATING CONSIDERATIONS

Strengths:

- PPAs provide a degree of earnings and cash flow stability
- 70% of non-PPA generation subject to medium and long-term sales contracts, with fuel cost owned/contracted/flow-through
- Low-cost generator of electricity
- Increasing geographic diversification

Challenges:

- Growing exposure to higher risk, non-regulated activities
- Business risk associated with PPAs
- Small size relative to North American peers
- Future environment costs and lower reliability associated with coal-based generation
- Risk of political interference

FINANCIAL INFORMATION

	12 mos. ending	For years ending December 31				
	Sept. 2002	2001	2000R	1999	1998	1997
Fixed-charges coverage (times)	1.63	1.91	2.11	2.06	2.70	2.66
% adj. debt in capital structure (1)	52.0%	54.8%	52.5%	49.3%	43.2%	41.2%
Cash flow/total adj. debt (times) (1)	0.17	0.19	0.21	0.18	0.24	0.24
Cash flow/capital expenditures (times)	0.46	0.48	0.73	0.69	1.48	1.50
Segmented Operating Income (cont. ops.)						
Regulated/PPAs (TransAlta Utilities)	248.8	365.3	172.3	267.9	349.2	437.8
Non-regulated	66.3	13.6	236.6	47.4	59.0	132.0
Operating income ($ millions)	315.1	378.9	408.9	315.3	408.2	569.8
Net income (bef. extras/disc. ops.) ($ millions)	163.1	185.2	161.2	123.3	164.6	203.1
Net income avail. to common ($ millions)	290.7	214.6	279.8	170.1	211.4	182.6
Operating cash flow ($ millions)	487.2	592.8	580.0	447.2	481.9	499.3
Total electricity sales (millions of kWh)	45,369	44,136	40,644	37,771	39,001	36,401

(1) Adjusted for equity treatment of hybrids securities. Pref. securities given 75% equity treatment, perpetual preferred shares 70%.
2000R: Transmission business treated as discontinued ops. effective 2000 to render results more comparable on forward-looking basis.

THE COMPANY

TransAlta Corporation is Canada's largest non-regulated electric generation and marketing company, with more than $7 billion in assets and about 9,000 MW of capacity (operational and under construction). TransAlta Corporation has generation plants in Canada, the U.S. and Mexico. The Company wholly owns TransAlta Utilities Corporation, an electricity generator in Alberta that owns and operates about 40% of the total capacity currently available to the Alberta market and whose assets are subject to long-term PPAs.

AUTHORIZED PAPER LIMIT Cdn$1 billion

Press Release

Dominion
Bond
Rating
Service
Limited

Date of Release: December 12, 2002 Energy

DBRS Downgrades TransAlta Utilities Corporation's Secured Debentures to A (low)

Geneviève Lavallée, CFA; Matthew Kolodzie, CFA / 416-593-5577 ext.2277, ext.2296 / glavallee@dbrs.com

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Downgraded	Secured Debentures
BBB (high)	Stable	Downgraded	Unsecured Debentures*

Note: Currently, there are no unsecured debentures outstanding.

The ratings on TransAlta Utilities Corporation's ("TAU" or the "Company") secured debentures and unsecured debentures are downgraded to A (low) and BBB (high), respectively. The trends are Stable.

The downgrade reflects the recent announcement by the Company regarding its Wabamum generation plant and the impact on its long-term outlook and risk profile. The Company announced that it would be taking a pre-tax write-down of $110 million related to the phased decommissioning of its Wabamum facility. TAC has shut down its 150 MW Wabamum Unit 3 effective November 29, 2002. The write-down includes a provision for replacing the power as would be required by the Power Purchase Arrangements (PPA). The Company also announced that Wabamum Units 1 & 2 (132 MW total) will be retired during Q1 2004, following the expiration of the PPA at the end of 2003. The 304 MW Unit 4 will continue to operate until the end of its licence in 2010.

The Company has had various operational problems with the Wabamum plant over the past two years, with the most recent experience providing clear evidence of TAC's higher risk profile due to its small size and the degree to which the Company is impacted financially by operational problems. The decision to reduce TAU's generating capacity by about 280 MW will reduce the Company's earnings and operating cash flows by about $25 million per year over the longer term.

The revised rating remains supported by the degree of earnings and operating cash stability offered by the PPAs. Over the medium term, earnings and operating cash flows will continue to be influenced by the degree to which TAU exceeds its availability targets and the electricity prices in effect at that time, as well as changes in long-term interest rates given the formula-based ROE targets. The key risk TAU faces continues to be the risk of not meeting operating targets set out in the PPAs.

TransAlta Utilities Corporation

Report Date: October 31, 2002
Press Released October 24, 2002
Previous Report: October 25, 2001

Geneviève Lavallée, CFA/Matthew Kolodzie, P.Eng.
416-593-5577 x2277/x2296
glavallee@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Secured Debentures*
A (low)	Stable	Confirmed	Unsecured Debentures**

* Publicly held debentures secured by a floating charge on the property and assets of TransAlta Utilities Corporation.
** There are no unsecured debentures currently outstanding.

RATING HISTORY	Current	2001	2000	1999	1998	1997	1996	1995
Secured Debentures	"A"	"A"	A (high)	AA (low)	AA (low)	AA (low)	AA	AA
Unsecured Debentures	A (low)	A (low)	NR	NR	NR	NR	NR	NR

RATING UPDATE

The long-term ratings on TransAlta Utilities Corporation ("TAU" or the "Company") are confirmed as above.

TAU has recorded favourable financial results since January 2001 when the new operating environment in Alberta came into effect, even including the negative financial impact of the *force majeure* decision in respect of the Wabumun unit 4 shutdown. For the 12 months ended September 30, 2002, TAU's financial results for continuing operations (the sale of the transmission assets closed in April 2002) and its key coverage and cash flow ratios were weaker than those recorded in 2001, but remain acceptable for the current ratings. It is expected that TAU's financial performance will improve somewhat over the near term, but will remain below that experienced in 2001. Over the medium term, earnings and operating cash flows should remain relatively stable. They will be impacted by the degree to which TAU exceeds its availability targets and the electricity prices in effect at that time, and changes in long-term interest rates given the formula-based ROE targets. Operating cash flows are expected to remain sufficient to cover annual capital expenditures.

The Company's long-term outlook remains reasonable although a number of risks and challenges exist that could impact its credit profile if not suitably managed. The key risk facing TAU is the risk of not meeting operating targets set out in the Power Purchase Arrangements ("PPAs"). The Company's exposure to unplanned outages relative to its peers will remain higher given the age of its assets and the fact they are primarily coal-based, which tend to be more sensitive to outages than other types of generators. Furthermore, given its lack of diversification across business segments and its small size relative to other North American generators, the financial impact from one unplanned outage is more significant for TAU than for larger, more diversified utilities. TAU currently faces competition only for electricity produced in excess of the availability targets set out in the PPAs. However, as the availability targets decline over the useful lives of the assets and as the PPAs expire (PPAs for 547.9 MW expire at the end of 2003), an increasing proportion of TAU's output will be subject to competition. The Company's risk profile will increase, but the increase should be limited by the degree of output it chooses to contract and the fact that most of the fuel is owned. The Company has generally been a low-cost and effective operator, which should provide it with a competitive advantage.

RATING CONSIDERATIONS

Strengths:
- PPAs provide for relative earnings and cash flow stability
- Strong operating cash flows, and key debt and coverage ratios
- Low-cost generator of power

Challenges:
- Business risk associated with PPAs
- Lack of diversification and small size
- Higher average age of assets
- Earnings sensitive to interest rates through ROE formula
- Risk profile will increase as PPAs expire

FINANCIAL INFORMATION

	12 mos. ended	For the year ending December 31				
	Sept. 2002	2001	2000R	1999	1998	1997
Fixed-charges coverage (times)	2.24	3.02	1.58	1.92	2.46	2.49
% adj. debt in the capital structure (1)	54.7%	52.3%	60.3%	54.4%	50.8%	52.4%
Cash flow/total adj. debt (1) (times)	0.15	0.21	0.24	0.20	0.24	0.25
Cash flow/capital expenditures (times)	1.66	1.43	1.89	1.45	2.09	1.96
Net income (bef. extras./disc. ops., after pfd.) ($ millions)	141.9	199.9	38.4	65.3	109.2	140.9
Operating cash flow (after pfd.) ($ millions)	266.1	377.0	373.2	323.7	348.7	378.5
Electricity sales (millions of kWh)	29,664	28,370	28,636	27,560	27,672	28,463
Variable costs* (cents per net gen kWh sold)	1.21	1.21	0.94	1.11	1.13	1.51
Fixed costs (cents per net gen kWh sold)	0.45	0.53	0.77	1.07	1.06	1.39
Average coupon on long-term debt	7.25%	7.25%	7.21%	7.78%	8.16%	8.78%

(1) Intercorp. preferred securities given 50% equity treatment, perpetual pref. shares given 70% equity treatment. * Before income taxes
2000R: Transmission business treated as discontinued ops. effective 2000 to render results more comparable on forward-looking basis.

THE COMPANY

TransAlta Utilities Corporation is a pure electricity generator in Alberta, and currently owns about 40% of the total capacity available to the Alberta market. All of its generation assets are subject to PPAs. The Company is wholly owned by TransAlta Corporation.

Press Release

Dominion Bond Rating Service Limited

Energy

Date of Release: January 31, 2003

DBRS Downgrades Veridian Corporation to A (low), Removed from UR-Negative

Matthew Kolodzie, CFA; Nigel Heath, CFA / 416-593-5577 ext.2296, ext.2228 / mkolodzie@dbrs.com

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Downgraded	Corporate Rating

DBRS is downgrading the corporate rating on Veridian Corporation ("Veridian" or the "Company") to A (low) from "A." The trend is Stable. The rating is removed from "Under Review with Negative Implications," where it was placed on November 12, 2002, following the announcement by the provincial government to lower electricity bills.

The rating action follows a full review, by DBRS, of the implications of Bill 210 on Veridian and the Ontario electricity industry as a whole. Key factors that have driven the downgrade are as follows:

(1) The cap on distribution rates at current levels until at least 2006: (a) the Company will not receive the final one-third instalment of its rate increase that it would have been entitled to charge beginning on March 1, 2003 to earn the previously approved 9.88% rate of return on equity, as such the ROE will essentially remain at 6.6%, which is low for a regulated distribution company; (b) continued uncertainty surrounding the recovery of certain items classified as regulatory assets; (c) the inability to recover increasing operating costs such as wage increases and higher pension costs; and (d) the inability to re-base its 1999 (the original test-year for setting unbundled rates) rate base amount to reflect capital additions and a growth in asset base. The rate cap will pressure the Company's cash flows and coverage ratios over the medium term. The initial rating assigned to Veridian had incorporated the rate increases to earn 9.88% and recover transition costs, and the expectation that the Company's rate base would be re-based upward during the second generation of PBR (scheduled for 2004/2005). Clearly, this is no longer the case.

(2) Having to seek the Minister's approval to increase rates for extraordinary items, hence bypassing the original mandate of the Ontario Energy Board to regulate distribution rates. Thus, the process will become more onerous.

(3) The continued risk of further government intervention in the Ontario electricity market.

The one-notch downgrade reflects these risks.

Veridian has received majority support (greater than 50%) from its municipal shareholders to remain as a commercial entity as set out in the resolution that gave the municipalities the option to declare whether it would (1) remain as a commercial entity, as it has been since first incorporating in 1999; or (2) revert back to being a not-for-profit entity. Becoming a not-for-profit entity would have warranted a further downgrade, as its financial profile would have become significantly weaker.

Veridian's rating continues to be supported by the following factors: (1) regulated distribution rates, while constrained by Bill 210, still provide a degree of stability to earnings and cash flow; (2) favourable franchise areas with well-diversified customer bases, and moderate to strong load growth rates which should contribute to stable earnings growth over the medium to long term; and (3) shareholder municipalities that are financially sound and are able to provide additional equity injections or limit dividend requirements, if necessary, to further support the Company's capital structure. In addition, the Company will no longer be subject to performance improvement targets, which were set as a part of the original performance-based regulation – this will reduce the pressure on earnings and cash flows somewhat.

A full update on Veridian's rating report will follow the release of the Company's 2002 financial statements.

Credit Rating Report

Veridian Corporation

Current Report: June 3, 2002

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	New Rating	Corporate Rating

Matthew Kolodzie, P.Eng., / Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING HISTORY	Current	2001	2000	1999	1998	1997
Corporate Rating	"A"	NR	NR	NR	NR	NR

COMMENTARY

DBRS is assigning a new corporate rating of "A" to Veridian Corporation ("Veridian" or "the Company"). The trend is Stable. The following key factors support the rating. (1) The Company is primarily involved in the regulated electricity distribution business (almost 100% operating income and 98% of fixed assets), which provides for a high degree of earnings and cash flow stability. (2) A well-diversified customer base with a moderate load growth rate will contribute to stable long-term earnings growth. (3) Operating cash flows and current cash balances are expected to be sufficient to finance its internal requirements over the medium term. As a result, its balance sheet should remain stable, and key cash flow and coverage ratios should continue to improve as new distribution rates are fully implemented. (4) The Company's shareholders are strong financially and hold $60.8 million in subordinated debt that could be converted to equity to finance investments in regulated or non-regulated activities.

The rating is currently constrained by a number of challenges largely related to industry restructuring. (1) The most important challenge facing the Company and the industry is political risk. As a result of the political pressures from the sharply higher electricity rates that would have resulted immediately from moving to the new regulatory environment, the Ontario Energy Board ("OEB") directed local distribution companies (LDCs) to phase in the initial rate increase required to generate the 9.88% target rate of return over a three-year period. Consequently, Veridian's profitability and interest coverage will remain weaker until rate increases are fully phased in. (2) Uncertainty exists regarding the future regulatory framework beyond 2003. It has yet to be decided if and how LDCs' rate bases will be re-based, how approved ROEs will be set in the future, how deferred market transition costs will be recovered and whether productivity targets will be the same for all LDCs or be set for groups of utilities having similar characteristics. Veridian's medium-term profitability and cash flow growth will depend on how these issues are resolved. (3) Diversification beyond regulated distribution increases business risk, although management is expected to maintain its conservative approach to investing in non-regulated activities. Over the medium term, non-regulated operations are expected to remain below 10% of consolidated assets, and similarly the impact of non-regulated activities on the stability of consolidated EBIT is expected to be minimal. (4) Financial flexibility is limited by the Company's inability to issue common equity (its equity base is limited to internal earnings growth or increases in equity from the conversion of subordinated debt into equity).

RATING CONSIDERATIONS

Strengths:

- Involved primarily in regulated electricity distribution
- Favourable franchise area
- Operating cash flows plus cash balances sufficient to cover capital expenditures over the next two years
- Financially strong shareholders
- Earnings growth potential from non-regulated subsidiaries

Challenges:

- Risk of political interference in the electricity sector
- Uncertainty related to the future regulatory framework
- Diversifying beyond regulated distribution
- Ability to meet performance improvement targets
- Lack of access to the public equity markets

FINANCIAL INFORMATION

	For the years ended December 31					
	2002F	2001p	2000p	1999p	1998p	1997p
Fixed-charges coverage (times)	2.37	0.42	0.18	(0.70)	2.57	2.30
% adjusted debt in capital structure	0.61	0.56	0.52	0.52	0.08	0.10
Cash flow/total adjusted debt (times)	0.10	0.12	0.09	0.08	1.13	0.85
Cash flow/capital expenditures (times)	0.86	0.71	0.85	0.62	1.39	0.91
Operating cash flow ($ millions)	11.6	11.2	7.2	6.4	8.8	8.4
Operating margin	31.4%	8.6%	1.4%	-2.8%	11.4%	12.4%
Return on average equity	2.9%	-3.0%	-1.8%	-1.3%	1.0%	2.0%
Electricity throughputs (millions kWh)	-	2,232	2,160	2,123	N/A	N/A
Customer base	-	89,175	88,760	86,202	83,712	83,232

p = pro forma of historical data for all seven former municipal utilities. F = forecast.

THE COMPANY

Veridian Corporation is a holding company that owns Veridian Connections Inc. ("VCI"), a regulated electricity distribution company; Veridian Energy Inc., which provides non-regulated billing and management services to VCI and external customers; and is a 43% shareholder of First Source, a retail electricity marketing company (57% held by Enersource Hydro Mississauga). Veridian Corporation is owned 41% by the City of Pickering, 32.1% by the Town of Ajax, 13.6% by the Municipality of Clarington and 13.3% by the City of Belleville. Its service area is an amalgamation of the former municipal electric utilities of the aforementioned municipalities, and it has also acquired the former utilities of Brock, Port Hope and Uxbridge.