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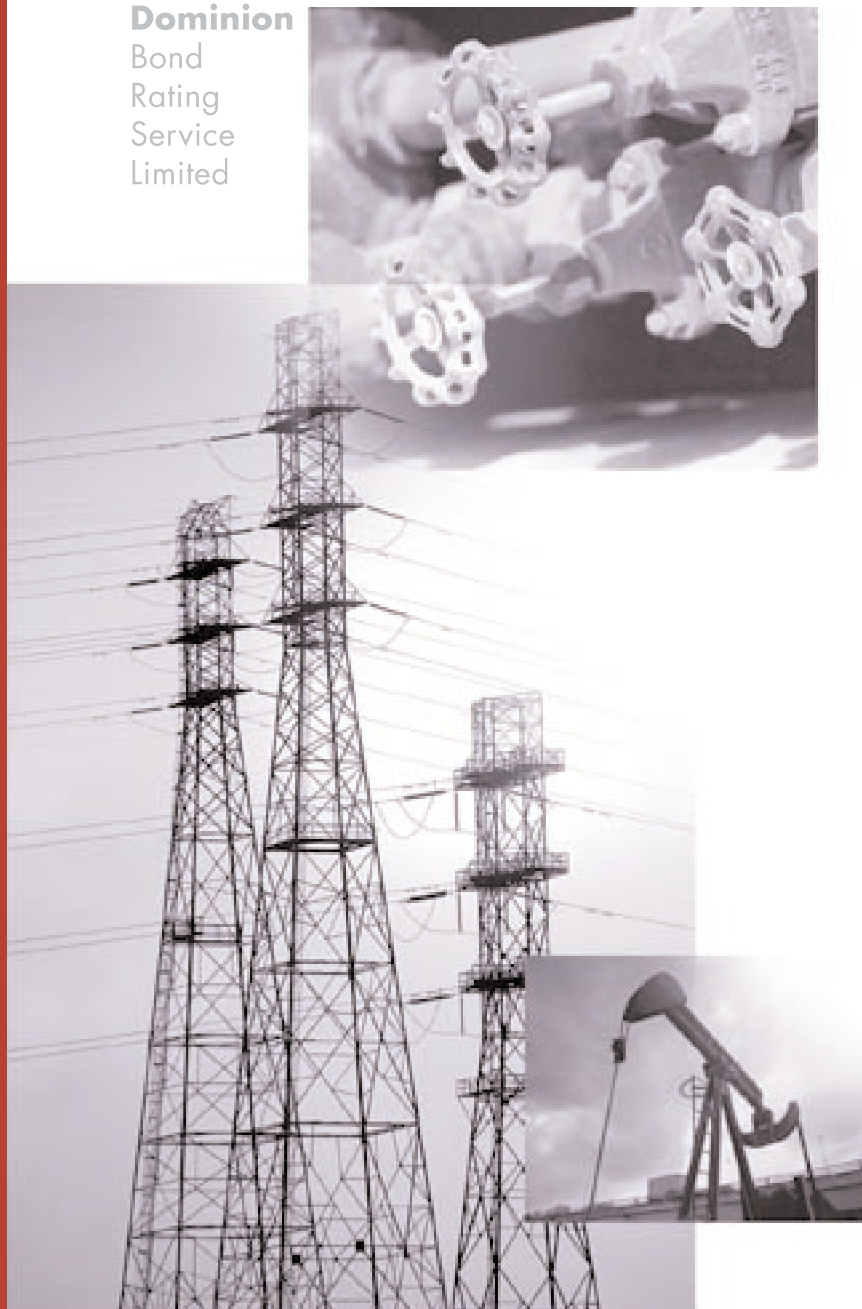
The Canadian Electric Utility Industry

Industry Study Utilities and Pipelines



NOVEMBER 2001

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Fiscal year-end	March 31	December 31	December 31	December 31	March 31	December 31	December 31	December 31	March 31	December 31	December 31		
Rating ^	*			*	guaranteed			guaranteed	*	guaranteed		**2000**	
Commercial Paper	R-1 (mid)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-2 (high)	-	-	
Long-Term Debt	AA (low)	A (low)	A (low)	A	A	A	A	A	A	BBB	A	-	
Preferred Shares					-	-				-		-	
Financial Ratios													
Current ratio	0.61	0.35	0.52	1.49	0.58	1.36	0.55	0.36	0.54	0.28	0.97	0.54	
Accumulated depreciation/gross fixed assets	36.0%	27.7%	43.4%	38.9%	28.9%	6.6%	32.5%	24.1%	45.4%	23.2%	40.2%	26.4%	
Cash flow/total debt (incl debt equiv)	0.13	0.14	0.14	0.18	0.08	0.27	0.15	0.08	0.07	0.06	0.14	0.11	
Cash flow/capital expenditures (1)	2.45	1.53	1.09	1.40	1.43	1.62	1.58	1.80	1.81	1.33	13.00	1.87	
Cash flow-dividends/capital expenditures (1)	1.54	1.10	0.66	1.06	1.43	1.27	0.70	1.55	1.81	(0.05)	8.44	1.48	
% net debt in the capital structure (incl debt equiv)	81.0%	65.7%	56.6%	54.6%	85.3%	31.5%	53.5%	73.2%	99.7%	66.4%	46.2%	69.0%	
Average coupon on l-t debt	7.80%	9.14%	7.77%	8.95%	8.38%	5.93%	8.13%	8.82%	8.39%	8.40%	7.71%	8.38%	
Common dividend payout (before extras.)	43.3%	47.2%	67.1%	54.8%	0.0%	33.9%	55.9%	50.0%	0.0%	200.3%	57.0%	44.3%	
Coverage Ratios (2)													
EBIT interest coverage	2.40	1.98	2.62	1.85	1.52	7.53	2.50	1.28	1.05	1.17	1.73	1.72	
EBITDA interest coverage	3.00	2.76	4.06	2.90	2.03	12.34	3.42	1.87	1.75	1.54	2.18	2.46	
Fixed charges coverage	2.40	1.98	2.62	1.85	1.52	7.53	2.50	1.28	1.05	1.17	1.73	1.72	
Earnings Quality / Operating Statistics													
Power purchases/total revenues	56.4%	28.1%	66.5%	6.2%	1.3%	3.0%	28.9%	15.0%	7.6%	6.7%	0.0%	24.0%	
Fuel costs/total revenues	5.8%	22.5%	0.0%	26.7%	2.2%	21.3%	-	6.1%	30.6%	14.0%	0.0%	10.1%	
Operating margin	18.0%	19.0%	18.5%	24.0%	46.2%	20.0%	43.7%	37.4%	21.9%	33.3%	42.1%	27.3%	
Net margin (bef extras., after pfd.)	10.9%	10.5%	17.7%	11.4%	19.4%	10.1%	17.9%	9.4%	0.0%	11.5%	28.2%	10.3%	
Return on avg common equity (before extras.)	60.4%	17.0%	13.4%	10.3%	28.3%	10.8%	9.9%	7.6%	0.0%	5.8%	7.8%	23.1%	
Approved ROE	-	-	-	-	-	-	9.88%	-	-	-	-	-	
% of profit returned to government	59.9%	59.6%	87.1%	66.1%	37.6%	72.2%	99.8%	65.1%	100.0%	176.8%	63.0%	68.6%	
Customers/employee	268	135	332	184	89	64	214	171	136	NM	8	153	
Growth in customer base	1.0%	0.0%	4.9%	0.8%	0.2%	NM	2.5%	0.7%	0.9%	NM	0.0%	1.2%	
GWh sold/employee (3)	12.1	5.0	7.3	7.3	6.3	9.3	36.8	9.2	7.2	8.1	143.6	8.9	
Total assets - $ millions	12,615.0	3,050.0	1,129.9	3,332.0	8,962.0	16,791.0	9,997.0	59,111.0	3,470.0	1,816.6	676.2	***120,950.7***	@
Total revenues - $ millions	7,889.0	1,421.4	748.2	1,101.0	1,393.0	5,978.0	2,995.0	11,429.0	1,309.0	303.2	96.5	***34,663.3***	@
Net earnings - $ millions	446.0	149.3	44.5	126.0	270.0	605.0	378.0	1,078.0	(12.0)	34.9	27.2	***3,146.9***	@
Electricity sold - millions of kWh	72,031	10,013	7,500	17,049	28,734	139,800	17,600	190,080	18,889	8,206	34,601	***544,502.8***	@
Capacity - MW	11,133	1,881	-	2,889	5,080	30,819	-	31,512	3,775	1,602	5,428	***94,119.0***	@
Interconnections - % of installed capacity	33.7%	100.0%	-	20.8%	54.4%	18.9%	-	23.5%	68.1%	0.0%	100.0%	***32.1%***	
Capital Structure ($ millions)													
Short-term debt	0.0	503.6	0.0	0.0	212.0	150.0	154.0	1,774.0	102.0	125.6	1.4	***3,022.6***	@
Long-term debt due 1 year (4)	415.0	86.7	172.5	0.0	435.0	204.0	474.0	3,395.0	245.0	162.9	42.7	***5,632.8***	@
Long-term debt (5)	6,485.0	1,171.4	357.2	1,571.0	5,678.0	3,219.0	3,972.0	35,067.0	2,624.0	834.8	263.1	***61,242.5***	@
Total debt	6,900.0	1,761.6	529.7	1,571.0	6,325.0	3,573.0	4,600.0	40,236.0	2,971.0	1,123.3	307.2	***69,897.8***	@
Preferred equity - common equivalents	0.0	0.0	0.0	0.0	0.0	0.0	323.0	0.0	0.0	0.0	0.0	***323.0***	@
Common equity (6)	1,459.0	919.5	340.6	1,248.0	1,088.0	5,817.0	3,677.0	14,467.0	8.0	568.6	350.7	***29,943.4***	@
TOTAL	8,359.0	2,681.1	870.3	2,819.0	7,413.0	9,390.0	8,600.0	54,703.0	2,979.0	1,691.9	657.9	***100,164.2***	@

^ Stable unless indicated. @ Group total. * Debt securities issued directly by the Provincial Government.

(1) Capital expenditures are net of customer contributions. For OPG, cash flows are adjusted for decommissioning and waste disposal expenses.

(2) Before non-cash financial charges. EBIT includes interest income. (3) For Hydro One, includes transmission sales.

(4) Net of sinking fund assets.

(5) Net of sinking fund assets. For Hydro-Quebec includes $552 million of perpetual debt. For Manitoba Hydro includes $1008.9 million in FX adjustments.

(6) For Hydro-Quebec includes $187 million of minority interest.

	Investor-Owned Electric Utility Comparisons							**Parent Holding Companies**			**Gov't Owned Utilities (9)**		
As at December 31, 2000 **Issuer**	**UtiliCorp Networks (BC)**	**ATCO Electric** (1)(a)	**TransAlta Utilities**	**N. Ontario Power** (1)(b)	**Nova Scotia Power**	**Group Average**		**CU Inc.**	**TransAlta Corporation**	**Great Lakes Power Inc.**	**EPCOR Utilities**	**Ont Power Generation**	**ENMAX Corp.**
Fiscal year-end	December 31	December 31	December 31	December 31	December 31			December 31	December 31	December 31	December 31	December 31	December 31
Current Rating ^						***2000***							
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)	R-1 (low)
Long-Term Debt	BBB (high) **	A (high)	A **	BBB (high)	A (low)	-		A (high)	A (low)	BBB (high)	A (low)	A	A (low)
Preferred Shares	-	Pfd-2 (high)		-	Pfd-2 (low)	-		Pfd-2 (high)	Pfd-2 (low) y	-	-	-	
Financial Ratios	**Notes**												
Current ratio	1.44	0.91	0.72	1.15	0.44	***0.66***		1.14	0.76	12.9	0.35	1.36	0.52
Acc. depreciation/gross fixed assets	29.2%	38.4%	46.1%	20.5%	34.5%	***38.8%***		37.4%	32.0%	19.3%	27.7%	6.6%	43.4%
Cash flow/total debt (incl debt equiv)	0.10	0.18	0.26	0.13	0.14	***0.18***		0.19	0.23	0.11	0.14	0.27	0.14
Cash flow/adjusted debt (incl debt equiv)	0.18	0.18	0.24	0.13	0.14	***0.18***		0.18	0.21	-	1.53	0.27	0.14
Cash flow/capital expenditures (2)	0.61	2.04	1.89	1.60	2.03	***1.85***		1.52	0.77	2.32	1.53	1.62	1.09
Cash flow-dividends/capital expenditures	0.42	1.15	0.39	1.09	1.26	***0.80***		1.05	0.52	0.92	1.10	1.27	0.66
% debt in the capital structure (incl debt equiv)	62.3%	55.6%	57.0%	34.3%	65.4%	***57.3%***		55.6%	50.5%	41.5%	65.7%	38.1%	56.6%
% adjusted debt in the capital structure	62.4%	58.1%	60.3%	34.5%	65.4%	***59.0%***		57.7%	53.9%	`	65.7%	38.1%	56.6%
Average coupon on l-t debt	7.96%	9.49%	7.21%	6.62%	7.59%	***7.90%***		8.96%	7.12%	8.19%	9.14%	5.93%	7.77%
Deemed/allowed equity (3)	40.0%	36.5%	40.0%	n/a	35.0%	***38.0%***		-	-	-	45.0%	-	-
Hybrids/common equity	0.0%	20.9%	25.2%	0.0%	0.0%	**11.9%**		13.5%	18.7%	-	0.0%	0.0%	100.0%
Common dividend payout (before extras.)	52.0%	99.7%	388.6%	76.9%	89.9%	***167.0%***		73.8%	94.8%	66.3%	47.6%	100.0%	67.1%
Coverage Ratios (4)													
EBIT interest coverage	2.27	2.94	2.49	2.34	2.30	***2.53***		2.62	3.58	2.04	1.98	8.56	2.62
EBITDA interest coverage	2.93	4.07	4.02	3.20	3.35	***3.73***		3.75	5.37	2.25	2.76	14.01	4.06
Fixed charges coverage	2.27	2.52	2.05	2.34	1.98	***2.17***		2.29	2.64	2.04	1.98	8.56	2.62
Earnings Quality / Operating Statistics													
Power purchases/total revenues	34.3%	10.7%	0.0%	39.1%	2.6%	***7.7%***		-	-	-	-	-	66.5%
Fuel costs/total revenues	0.0%	14.1%	16.4%	0.0%	30.8%	***18.7%***		-	-	-	-	-	0.0%
Operating margin	24.7%	36.5%	36.0%	25.3%	31.1%	***33.4%***		19.6%	31.7%	59.1%	19.0%	20.0%	18.5%
Net margin (bef extras., after pfd.)	9.4%	12.7%	10.3%	10.5%	12.7%	***11.7%***		6.8%	11.2%	29.4%	10.4%	10.1%	17.7%
Return on avg common equity (before extras.)	10.4%	12.3%	7.5%	2.8%	10.9%	***9.0%***		11.7%	12.7%	7.9%	16.8%	10.8%	13.4%
Approved ROE	10.00%	(5)	9.25%	9.88%	10.75%	-		-	-	-	9.25%	-	
Customers/employee (6)	213	204	-	89	248	***161***							
Growth in customer base (6)	1.3%	2.2%	-	-1.3%	0.9%	**1.3%**							
GWh sold/employee	6.6	10.7	22.1	17.9	6.0	***11.9***							
Rate Base - millions	$318.2	$2,025.0	$2,553.6	-	$2,410.7	***$7,307.5***	@						
Growth in rate base	13.8%	8.6%	-22.1%	-	1.5%	-							
Total assets - millions	$367.3	$2,220.9	$3,039.7	$782.1	$2,838.7	***$9,248.7***	@	$4,280.8	$7,627.1	$2,476.0	$3,050.0	$16,071.0	$1,129.9
Total revenues - millions	$138.9	$734.2	$741.9	$123.7	$819.2	***$2,557.9***	@	$2,248.0	$1,587.0	$333.5	$1,421.4	$5,978.0	$748.2
Net earnings - millions (after pfd)	$13.1	$93.4	($56.9)	$13.0	$103.7	***$166.3***	@	$153.1	$279.8	$97.9	$149.3	$605.0	$44.5
Electricity sold - millions of kWh	2,717	9,983	28,636	2,309	10,656	***54,301.2***	@	-	41,408	3,372	10,013	139,800	7,500
Capacity - MW	205	1,388	4,476	327	2,183	***8,579.0***	@	-	6,870	680	1,881	30,819	-
Interconnections - % of installed capacity	100%	100%	100%	100%	23%	***79%***		-	-	-	100.0%	16.5%	-
Capital Structure													
Short-term debt (7)	0.0	197.2	207.9	0.0	274.1	***679.2***	@	223.1	772.7	0.0	503.6	150.0	0.0
Long-term debt due 1 yr	0.0	0.0	76.7	0.0	120.5	***197.2***	@	7.2	79.6	0.0	86.7	204.0	172.5
Long-term debt	212.8	965.0	1,161.1	244.6	1,155.0	***3,738.5***	@	1,750.2	1,821.8	952.3	1,171.3	3,219.0	357.2
Debt equivalent preferreds	0.0	0.0	0.0	0.0	249.1	***249.1***	@	0.0	0.0	94.2	0.0	0.0	0.0
Total debt	212.8	1,162.2	1,445.7	244.6	1,798.7	***4,864.0***	@	1,980.5	2,674.1	1,046.5	1,761.6	3,573.0	529.7
Preferred securities	0.0	0.0	98.0	0.0	0.0	***98.0***	@	0.0	292.0	0.0	0.0	0.0	0.0
Perpetual preferreds	0.0	158.7	121.6	0.0	0.0	***280.3***	@	256.5	121.6	0.0	0.0	0.0	0.0
Common equity (8)	128.3	760.4	872.7	464.9	953.0	***3,179.3***	@	1,326.5	2,210.8	1,249.0	919.5	5,817.0	340.6
TOTAL - millions	$341.1	$2,081.3	$2,538.0	$709.5	$2,751.7	***8,421.6***	@	$3,563.5	$5,298.5	$2,295.5	$2,681.1	$9,390.0	$870.3

(1) Ratios reflect operations of electric utilities, ratings is that of parent, (a) CU Inc. (b) Great Lakes Power. ** Secured. ^ Stable unless indicated. @ Industry total.

(2) Capital expenditures are net of customer contributions.

(3) CU Inc. and Great Lakes have no deemed equity. Value represents actual.

(4) Before non-cash financial charges. Capitalized interest/AFUDC/equity income included for Great Lakes Utility. (5) Negotiated settlement.

(6) TransAlta sold its distribution and transmission in 2000.

(7) For N.S. Power, includes $72 million in receivable sales.

(8) For Great Lakes Power Inc. incl $248 milion of convertible debt. For TransAlta Corp includes $253.4 million minority interest.

(9) Gov't owned utilities. Debt is not guaranteed by parent. Ratings reflect the credit considerations of the operating entity.

Government-Owned Integrated Electric Utility Comparisons

As at December 31, 2000 / Issuer	B.C. Hydro	EPCOR Utilities	ENMAX Corp.	Sask. Power	Manitoba Hydro	Ont. Power Generation	Hydro One	Hydro Québec	N.B. Power	Nfld. & Lab. Hydro	Churchill Falls
Fiscal year-end	March 31	December 31	December 31	December 31	March 31	December 31	December 31	December 31	March 31	December 31	December 31
Rating ^	*			*	guaranteed			guaranteed	*	guaranteed	
Commercial Paper	R-1 (mid)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-2 (high)	-
Long-Term Debt	AA (low)	A (low)	A (low)	A	A	A	A	A	A	BBB	A
Preferred Shares					-	-				-	
Unit Revenues (1)					(cents per kWh sold)						
Domestic revenues	4.93	6.50	9.18	6.14	4.69	4.11	1.80	5.10	6.64	4.30	0.17
Export revenues (2)	22.84	19.95	-	7.55	3.97	6.98	-	6.38	6.81	0.89	0.29
Average electricity revenues	10.87	11.11	9.18	6.33	4.39	4.19	1.80	5.35	6.69	3.68	0.28
Ancillary revenues	0.08	3.08	0.79	0.12	0.46	0.09	0.02	0.66	0.24	0.02	0.00
Average unit revenues	10.95	14.20	9.98	6.46	4.85	4.28	1.82	6.01	6.93	3.69	0.28
Self Generation Cost Structure					(based on cents per net generated kWh sold)						
Operating + administrative	1.62	2.78	-	1.90	1.03	1.61	-	1.51	1.57	1.62	0.10
Fuel	0.98	3.19	-	2.11	0.11	0.93	-	0.51	2.36	0.74	0.00
Variable costs (excl income taxes)	2.60	5.98	-	4.01	1.14	2.54	-	2.02	3.93	2.35	0.10
Gov't levies	0.92	0.47	-	0.32	0.58	0.28	-	0.52	0.29	0.19	0.01
Net interest expense	1.12	1.37	-	0.94	1.38	0.12	-	2.39	1.59	1.48	0.04
Total cash costs	3.52	6.44	-	4.33	1.72	2.82	-	2.54	4.22	2.54	0.11
Non-cash financial charges	0.08	(0.14)	-	0.05	(0.04)	(0.01)	-	(0.13)	0.09	(0.03)	0.00
Depreciation	0.82	1.06	-	1.19	0.89	0.56	-	1.38	1.21	0.62	0.05
Total costs (excl income taxes)	4.42	7.36	-	5.57	2.57	3.37	-	3.78	5.52	3.13	0.16
Total fixed costs (deprec/interest/levies)	2.94	2.75	-	2.50	2.81	0.94	-	4.16	3.19	2.25	0.10
Purchased power (cents/gross kWh purchased) (3)	16.31	0.00	6.63	1.87	1.99	4.74	4.92	2.98	4.78	0.80	0.00
Average Unit Costs					(based on cents per kWh sold)						
Costs:											
Operating + administrative	1.05	2.78	1.40	1.55	1.01	1.56	0.50	1.12	1.41	1.14	0.10
Purchased power	6.18	3.99	6.63	0.40	0.06	0.13	0.53	0.90	0.53	0.25	0.00
Fuel	0.63	3.19	0.00	1.73	0.10	0.91	0.00	0.36	2.12	0.52	0.00
Variable costs	7.86	9.97	8.03	3.68	1.17	2.60	1.03	2.39	4.06	1.90	0.10
Gov't levies	0.60	0.47	0.92	0.26	0.57	0.27	0.02	0.37	0.26	0.13	0.01
Net interest expense	0.72	1.37	0.16	0.77	1.34	0.11	0.22	1.77	1.43	1.04	0.04
Total cash costs	9.18	11.80	9.10	4.71	3.08	2.99	1.26	4.53	5.76	3.07	0.15
Cash margin	1.77	2.39	0.87	1.75	1.76	1.29	0.56	1.48	1.17	0.63	0.13
Non-cash financial charges	0.05	(0.14)	(0.13)	0.04	(0.04)	(0.01)	(0.01)	(0.10)	0.08	(0.02)	0.00
Depreciation	0.53	1.06	0.41	0.97	0.87	0.55	0.21	1.00	1.09	0.43	0.05
Pre-tax margin	1.19	1.48	0.59	0.74	0.94	0.76	0.36	0.58	0.00	0.21	0.08
Variable costs (excl income taxes)	7.86	9.97	8.03	3.68	1.17	2.60	1.03	2.39	4.06	1.90	0.10
Fixed costs (deprec/interest/levies)	1.90	2.75	2.81	2.04	2.74	0.92	0.43	3.05	2.87	1.58	0.10
Total costs (excl income taxes)	9.76	12.72	10.84	5.72	3.91	3.52	1.46	5.44	6.93	3.48	0.20
Generation Mix (based on installed capacity)											
Coal	0.0%	43.6%	-	57.4%	0.0%	24.5%	-	0.0%	13.6%	0.0%	0.0%
Gas	8.2%	55.7%	-	13.1%	4.5%	0.0%	-	0.0%	0.0%	0.0%	0.0%
Hydro	89.9%	0.7%	-	29.5%	95.3%	23.5%	-	92.8%	23.4%	56.1%	100.0%
Nuclear	0.0%	0.0%	-	0.0%	0.0%	45.0%	-	2.1%	16.8%	0.0%	0.0%
Oil	1.9%	0.0%	-	0.0%	0.2%	6.9%	-	5.0%	46.1%	43.9%	0.0%
	100.0%	100.0%	-	100.0%	100.0%	100.0%	-	100.0%	100.0%	100.0%	100.0%

^ Stable unless indicated * Debt securities are issued directly by the Provincial Government.

(1) Industry average excludes Hydro One. (2) For EPCOR, represents sale of surplus power to the Alberta Power Pool.

(3) For Hydro-Quebec (and industry average), includes Churchill Falls purchases.

Investor-Owned Integrated Electric Utility Comparisons

As at December 31, 2000 **Issuer**	**UtiliCorp Networks Canada (BC)**	**ATCO Electric**	**TransAlta Utilities**	**N. Ontario Power** (1)(b)	**Nova Scotia Power**	**Group Average**
Fiscal Year-end	December 31	December 31	December 31	December 31	December 31	
Current Rating ^						
Commercial Paper	-	R-1 (low)	-	R-1 (low)	R-1 (low)	-
Long-Term Debt	BBB (high) **	A (high)	A **	BBB (high)	A (low)	-
Preferred Shares	-	Pfd-2 (high)		-	Pfd-2 (low)	-
Unit Revenues	(cents per kWh sold)					
Domestic revenues	4.96	6.64	2.59	5.36	7.63	***4.56***
AEEMA/ASPRDA	0.00	0.72	0.00	0.00	0.00	***0.13***
Average electricity revenues	4.96	7.35	2.59	5.36	7.63	***4.56***
Ancillary revenues	0.15	0.00	0.00	0.00	0.06	***0.02***
Average unit revenues	5.11	7.35	2.59	5.36	7.69	***4.71***
Self Generation Cost Structure	(based on cents per net generated kWh sold)					
Operating + administrative	1.96	1.80	0.56	1.46	1.51	***1.03***
Fuel	0.00	1.20	0.43	0.00	2.43	***0.96***
Variable costs (excl income taxes)	1.96	2.99	0.99	1.46	3.95	***1.99***
Gov't levies	1.56	0.29	0.11	0.78	0.17	***0.21***
Net interest expense	1.13	1.03	0.38	0.68	1.06	***0.66***
Total cash costs	4.65	4.32	1.49	2.92	5.18	***2.87***
Non-cash financial charges	(0.04)	(0.03)	(0.01)	(0.01)	0.16	***0.02***
Depreciation	0.74	1.21	0.59	1.05	1.12	***0.82***
Total costs (excl income taxes)	5.34	5.51	2.06	3.97	6.45	***3.71***
Total fixed costs (deprec/interest/levies)	3.38	2.51	1.07	2.51	2.51	***1.72***
Income taxes	0.50	0.92	0.26	0.69	0.14	***0.37***
Purchased power (cents/gross kWh purchased)	3.10	5.65	0.00	4.88	7.18	***4.14***
Preferred dividends	0.00	0.10	0.05	0.00	0.10	***0.06***
Average Unit Costs	(based on cents per kWh sold)					
Costs:						
Operating + administrative	0.97	1.55	0.55	0.84	1.47	***0.95***
Purchased power	1.75	0.79	0.00	2.10	0.20	***0.36***
Fuel	0.00	1.03	0.42	0.00	2.37	***0.88***
Variable costs	2.72	3.37	0.97	2.94	4.04	***2.19***
Gov't levies	0.77	0.25	0.11	0.45	0.17	***0.20***
Net interest expense	0.55	0.89	0.38	0.40	1.04	***0.61***
Total cash costs	4.04	4.51	1.46	3.79	5.25	***2.99***
Cash margin	1.07	2.84	1.13	1.57	2.44	***1.72***
Non-cash financial charges	(0.02)	(0.03)	(0.01)	(0.00)	0.15	***0.02***
Depreciation	0.36	1.05	0.58	0.61	1.09	***0.75***
Pre-tax margin	0.73	1.82	0.57	0.96	1.20	***0.95***
Income taxes	0.25	0.80	0.26	0.40	0.14	***0.34***
Net margin	0.48	1.02	0.31	0.56	1.07	***0.61***
Variable costs (excl income taxes)	2.72	3.37	0.97	2.94	4.04	***2.19***
Fixed costs (deprec/interest/levies)	1.66	2.17	1.05	1.45	2.44	***1.58***
Total costs (excl income taxes)	4.38	5.54	2.02	4.40	6.49	***3.76***
Preferred dividends	0.00	0.08	0.04	0.00	0.09	***0.06***
Generation Mix (based on installed capacity)						
Coal	0.0%	86.7%	82.1%	0.0%	58.3%	***71.7%***
Gas	0.0%	7.8%	0.0%	0.0%	8.2%	***3.4%***
Hydro	100.0%	0.0%	17.9%	100.0%	17.5%	***20.0%***
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	***0.0%***
Oil	0.0%	5.5%	0.0%	0.0%	16.0%	***5.0%***
	100.0%	100.0%	100.0%	100.0%	100.0%	***100.0%***

(1) Ratios reflect operations of electric utilities, ratings are those of parent: (a) CU Inc. (b) Great Lakes Power.

** Secured. ^ Stable unless indicated.

Overview of Canadian Electricity Industry

Restructuring of the electricity industry has generally proceeded very slowly in Canada compared to the U.S. This can largely be explained by the dominance of government-owned electric utilities in Canada and the lack of political incentive to restructure. Over the last year, however, restructuring continued in Alberta, with the market opening on January 1, 2001, and in Ontario, where restructuring is in an advanced stage with the competitive market set to open in May 2002.

Limited inroads have been made toward the restructuring of the electricity industry in other provinces.

In New Brunswick, the provincial government has laid the groundwork for transition by implementing wholesale competition and allowing non-utility generation and retail competition for large industrial customers by April 2003, while waiting until conditions prove more favourable before permitting full retail competition.

In Québec, the wholesale electricity market has been open to competition since 1997 and generation became unregulated in 2000. However Hydro-Québec retains sole responsibility for developing sites with a capacity of over 50 MW.

The Saskatchewan government, in November 2001, implemented an Open Access Transmission Tariff (“OATT”), which is paid by eligible users to access the provincial 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.

In Manitoba, the provincial government amended the Manitoba Hydro Act to grant open access to the provincial transmission system, which allows other utilities to wheel electricity across Manitoba and into neighbouring states and provinces.

In British Columbia, the wholesale market has been open to competition since 1997, when BC Hydro’s export subsidiary, Powerex, received its FERC marketing license.

Alberta

On January 1, 2001, retail competition was introduced partially in Alberta as retail customers can choose the regulated rate option (a flow-through of commodity costs), which is available for five years for residential and farm customers, and for three years for small commercial and small industrial customers. The power purchase agreements (“PPAs”), which cover generation that was in service at December 1995 and allows for the continuation of cost recovery for these assets, also became effective January 1, 2001, while the pricing for electricity from generation assets in service after December 1995 is market based. The operating and financial results since market opening have brought to the forefront some of the outcomes and risks identified by DBRS.

As expected, earnings related to the generation assets subject to the PPAs have increased significantly relative to the previous regime due to the higher allowed ROE and the increase in the deemed equity component. On the negative side, the results to date have demonstrated the risks that exist for the owners of the generation assets subject to the PPAs. The current TransAlta Utilities case has proven the difficulty associated with defining force majeure. The generators are also exposed to operating risk of not meeting availability targets set out in the PPAs, and some generators have already incurred such penalties.

Ontario

In Ontario, market opening (retail and wholesale competition) was delayed from the initial date of November 2000 and a new date of May 2002 has been set. In preparation for the new environment, Ontario Power Generation has made significant progress over the past year in reducing its market share (as required by government policy) and in getting its Pickering A nuclear plant back on line to ensure sufficient supply when the market opens.

Risks

For the electric utilities operating in Alberta or Ontario, the most important risks to their current credit profiles are related to the operating risks of these new environments: (1) managing commodity price risk for retailers; (2) merchant power risk for generators; (3) volume risk for generators subject to the PPAs; and (4) risk of political interference given the experience to date and the experiences of other jurisdictions in North America.

For the electric utilities that operate outside Alberta and Ontario, the primary challenges continue to be dealing with the regulators in those provinces and, for government-owned utilities, improving their balance sheets and key coverage ratios.

Outlook

The growing 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 sold within the territory served by the RTO. All public utilities that own, operate or control electric transmission assets in the U.S. must form or join an RTO. The RTOs must be operational by December 15, 2001. 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 this 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.

Characteristics of the Canadian Electricity Industry

- Weather is a significant factor that influences electricity demand and supply in Canada, due to climatic extremes
- Hydro-based generation with storage capacity increases profitability from electricity trading
- Seasonable characteristic of electricity demand in Canada is changing – air conditioning growing
- Shortage of transmission interconnections persists, especially east-west interconnections
- Natural gas price beginning to have more influence on electricity prices in Canada
- Canadian utilities cost competitive with U.S. utilities
- Regional Transmission Organizations (RTO) make Canadian electricity more competitive in the U.S.
- Government-owned utilities continue to have very high debt levels, but leverage is decreasing
- Government-owned utilities pay no corporate taxes
- Line losses in transmission high – 10%-15% for some utilities
- Fragmented industry – companies generally small compared to U.S. utilities

Weather a significant factor that influences supply and demand

Weather is one of the most significant factors that influences the demand for and supply of electricity in Canada. First of all, 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 installed air conditioners are electrically powered. Thus, cooler winters and warmer summers increase the seasonal peak demand and overall consumption of electricity. Furthermore, 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. Higher rainfall levels in a given watershed will result in more runoff that is available for hydro generation. Similarly, greater amounts of snowfall in the winter months result in higher seasonal snow pack levels, which translates to more spring runoff that is available for generation.

Hydro-based generation with storage capacity increases profitability from electricity trading

Provincial utilities such as BC Hydro, Manitoba Hydro and Hydro-Québec have a high proportion of hydro-based generation with substantial storage capacity, which has allowed these utilities to profit from electricity trading. While electricity is a commodity that cannot be stored, as the amount of electricity that is generated is directly proportional to the amount that is demanded at a given point in time, water can be stored behind dams for later usage. Thus, during periods of low electricity demand and low prices, such as at night, water volumes are built up as generators sit idle or generate below capacity. During the day, when electricity demand peaks and prices are higher, the stored water is drawn down as generators are set to full capacity. This allows hydro generators to generate more electricity during higher priced periods and generate less during lower priced periods. This is in contrast to coal-based generators, for example, which must run at full capacity all the time, as the shutdown process is costly. BC Hydro has benefited substantially from electricity trading with its significant storage capacity and its proximity to power-short Alberta and the Northwestern U.S.

Seasonal demand factors for electricity are changing

Demand for electricity in Canada has typically had a winter bias, with the greatest demand occurring during the months of January and February when the weather was coldest. This is changing, however, as air conditioning usage grows. Many provinces are recording dual electricity demand peaks, namely summer peaks that are near or higher than winter peaks. For example, Ontario Power Generation hit its record peak demand in August 2001 as a result of an unusually warm summer in Ontario and increased air conditioning usage.

Shortage of transmission interconnections

A shortage of transmission interconnections persists in Canada, and is unlikely to change. There are limited east/west interconnections in Canada, with the exception of Ontario and Québec. Most interconnections are north/south with the U.S. rather than with other provinces. New Brunswick Power and Manitoba Hydro have the highest proportion of their generation capacity interconnected, while Hydro-Québec and Ontario Power Generation have the highest absolute interconnections. New interconnection development is proceeding slowly. Some of the significant projects currently under development include a 1,250 MW interconnection between Ontario and Québec, an additional 1,000 MW of export capacity and 500 MW of import capacity between Ontario and Michigan through the installation of three phase-shifting transformers and an autotransformer, and a 230 kV line that Manitoba is installing into North Dakota. Public opposition to the construction of transmission lines is the primary reason for slow growth in interconnection, and this attitude is unlikely to change soon.

Natural gas prices beginning to have more influence on electricity prices in Canada

The generation mix in Canada is roughly 58% hydro, 17% coal, 15% nuclear, 5% oil and 4% natural gas. While natural gas-based generation remains a small component of the overall mix, the majority of new generation capacity being built is fueled by natural gas. Given the tight supply/demand conditions that currently exist in Alberta and Ontario and the fact that new generation is largely gas-based, the cost of gas-based generation is becoming the marginal price setter for electricity in these provinces. Therefore, the price of gas is becoming an increasingly important factor in the determination of electricity prices in Alberta and Ontario.

Canadian utilities remain cost competitive with U.S. utilities

Unit electricity costs (generation, transmission and distribution), excluding income taxes, in Canada range from about Cdn3.50¢ per kWh (Newfoundland & Labrador Hydro) to Cdn7.00¢ per kWh (New Brunswick Power). Unit retail prices are slightly higher and range from Cdn4.30¢ per kWh (Newfoundland & Labrador Hydro) to Cdn7.63¢ per kWh (Nova Scotia Power). Average unit retail prices in Canada remain significantly below those in the U.S.: Cdn5.78¢ per kWh vs. about US7.30¢ per kWh. Some of the key reasons for the lower average costs and retail prices in Canada are: (1) the dominance of low-cost hydro-based generation; and (2) the 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.

Regional Transmission Organizations (RTO) enhance the competitiveness of Canadian utilities vs. U.S. utilities

In the past, one of the greatest problems for Canadian electricity exporters was the pancaking of transmission tariffs, as electricity was exported southward and from state to state. This had the effect of limiting the number of U.S. utilities to which Canadian electricity could be sold at a competitive price, as the postage stamp charges were onerous (0.50¢-0.75¢ per kWh for the use of a single utility's transmission system). The establishment of RTOs and, thus, only one transmission charge for electricity sold within the territory served by an RTO will reduce the costs of exporting and increase the competitiveness of Canadian electricity, especially in areas with high demand and short supply.

Government-owned utilities continue to have high debt levels, but leverage is decreasing

The proportion of debt in the capital structure of government-owned utilities generally remains high, although leverage has been improving over the last eight years. The general improvement is due to: (a) earnings growth and the lack of aggressive capital expenditure plans; and (b) less pressure from the provincial governments for large dividend payments due to the improved fiscal situations of the provinces. A few government-owned utilities still have excessive leverage of over 80% (BC Hydro, Manitoba Hydro and New Brunswick Power), which is significantly higher than the typical leverage of investor-owned utilities, within the 50%-70% range. However, with the onset of deregulation, many investor-owned utilities are increasing their leverage through aggressive expansion programs, while government-owned utilities are generally focusing on improving their balance sheets.

Government-owned utilities pay no corporate taxes

Government-owned utilities do not pay corporate taxes, although Ontario Power Generation, Hydro One, EPCOR Utilities and ENMAX Corporation are now required to make payments-in-lieu of taxes to ensure there is a level playing field among utilities. As a result, government-owned utilities have a significant advantage over investor-owned utilities that pay, on average, income taxes of about 0.50¢ per kWh. This advantage also discourages governments from privatizing their electric utilities.

High line losses in transmission

Transmission line losses in Canada amount to 6%-8%, while line losses related to distribution are about 2%-4%. The high line loss rate is related to the long distances over which Canadian electricity must be transmitted.

Fragmented Canadian industry

The Canadian industry is extremely fragmented relative to the U.S. industry for the following reasons. There are a number of mergers underway in the U.S., creating much larger entities. The fact that over 90% of Canadian capacity is government owned is limiting the number of mergers that could take place in Canada. Thus, many smaller companies, that do not have the size and, thus, the diversification benefits of some U.S. utilities, exist within Canada.

INDUSTRY RESTRUCTURING IN CANADA

BRITISH COLUMBIA

Characteristics of the British Columbia Market

British Columbia Hydro and Power Authority ("BC Hydro"), a Crown corporation with about 1.5 million customers, and UtiliCorp Networks Canada (British Columbia) Ltd. ("UNBC"), formerly known as West Kootenay Power Ltd. are the vertically integrated utilities in British Columbia. BC Hydro serves approximately 94% of electricity customers in British Columbia and UNBC serves most of the remainder of the province, except for certain large industries and a few local areas and municipalities.

BC Hydro owns over 80% of the provincial generating capacity (11,115 MW) with over 90% hydro-based generation. The remaining capacity is owned by the Columbia Power Corporation ("CPC"), industrial plants, and various independent power producers such as UNBC and others. The CPC is 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. CPC currently has two projects underway, with a combined capacity of 190 MW.

Interconnection: The grid is connected to Alberta and to Washington State. Current transfer capability is 3,150 MW from British Columbia to the United States, 2,000 MW from the United States to British Columbia, 1,000 MW from Alberta to British Columbia, and 1,200 MW from British Columbia to Alberta. This substantial interconnection capacity, along with an extensive hydro base with storage capability, provides BC Hydro with the ability to profit from energy trading. 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.

The British Columbia Power Exchange Corporation ("Powerex"), is a wholly owned electricity trade 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 U.S. Key trading partners include utilities, large industrial customers, cogenerators, independent power producers and marketers.

Regulation in British Columbia

The wholesale market has been open to competition since 1997, when BC Hydro's export subsidiary, Powerex, received its FERC marketing license. There are currently no plans to further restructure in British Columbia.

B.C. Hydro is regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC establishes and approves customer rates, allowed rates of return on deemed common equity ("ROE"), approval on new projects, and annual payments to the province. Both BC Hydro and the BCUC are subject to directives issued by the Province of British Columbia. The approved ROE is set at a rate equivalent to the pre-tax return allowed for investor-owned utilities. The approved pre-tax ROE for the years ended March 31, 2001 and 2000 was 16.69% versus 17.47% in 1999. B.C. 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 the Utility's debt-to-equity ratio after deducting the payment does not exceed 80:20. 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 30, 2003.

UNBC is also subject to regulation by the BCUC. UNBC's ROE is linked to the forecast long-term Government of Canada bond yield. As a regulated utility, the UNBC's balance sheet leverage and coverage ratios must be maintained with a 60/40 debt/equity structure. UNBC's electricity rate increases are established each year to achieve an approved ROE. For 2001, the BCUC approved an ROE of 9.75% (which compares to 10.0% in 2000 and 9.5% in 1999). In mid-1996, UNBC 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 UNBC with incentives for improving operating efficiencies with 50%/50% sharing of savings between UNBC 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 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 40% of UNBC's total electrical load) to choose an alternative electricity supplier. This ruling has not had a material impact to date.

ALBERTA

Characteristics of the Alberta Market

The Alberta market has peak demand close to 8,000 MW and total installed capacity of about 10,300 MW (includes independent power producers and other non-utility generation). Despite the size of Alberta's electricity market, it has limited interconnections, consisting of 1,000 MW from Alberta to British Columbia, and 1,200 MW from British Columbia to Alberta, and 150 MW with Saskatchewan. The major generators include TransAlta Corporation with 4,500 MW (utility) and 400 MW (independent power producers), Canadian Utilities with 1,162 MW (utility) and 400 MW (independent power producers) and EPCOR Utilities with 1,701 MW (utility) and 180 MW (independent power producers).

Canadian Utilities, EPCOR Utilities, ENMAX Corporation and UtiliCorp Networks Canada (Alberta) are the major holders of distribution assets in Alberta, while Canadian Utilities, EPCOR Utilities, ENMAX Corporation and AltaLink (once sale of transmission assets from TransAlta Utilities closes) are the major holders of transmission assets in Alberta.

Canadian Utilities Limited is a holding company whose principal subsidiaries include regulated electric and gas transmission and distribution utilities primarily based in Alberta, in addition to non-regulated utility subsidiaries and holdings in England, Australia and Canada.

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. (2) ENMAX Energy Corporation, a non-regulated entity that primarily markets electricity to roughly 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 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; and (2) non-regulated independent power plants in Alberta, B.C. and Washington; retail energy services including natural gas and electricity; and wholesale energy marketing. EPCOR Utilities is wholly owned by the City of Edmonton.

UtiliCorp Networks Canada (Alberta) Ltd. is involved exclusively in electricity distribution in Alberta. Its franchise region is located in central and southern Alberta. AltaLink (once the sale closes, expected in Q2 2002) will be involved in the transmission of electricity in Alberta.

Current Market Environment

Key features of the new competitive environment, effective 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 (a flow-through of commodity costs). This option is available for five years for residential and farm customers, and for three years for small commercial and small industrial customers.
- *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 PPAs*. The PPAs incorporate annually adjusted, formula-based ROEs, consisting of a fixed 450 basis point risk premium above forecast 10-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 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.

Results To date of New Operating Environment

Generation assets subject to PPAs

For the nine months ending September 30, 2001, the electric utilities that own generation assets subject to the PPAs (TransAlta Utilities Corporation, Canadian Utilities and EPCOR Utilities) have experienced significant increases in the earnings related to these assets due to the higher allowed ROE of 450 basis points over 10-year Government of Canada bonds and the increase in the deemed equity component to 45%.

While the level of earnings has increased significantly, the results to date have demonstrated the risks that exist for the owners of the generation assets subject to the PPAs. An important risk is establishing who is at fault and defining "force majeure" in the event of an unplanned shutdown. The current TransAlta Utilities case with its Wabumun unit 4 shutdown has proven the difficulty associated with defining force majeure. The Alberta Balancing Pool ruled against TransAlta Utilities and the case is currently with arbitrators. TransAlta Utilities' maximum financial exposure relating to this shutdown is approximately $90 million. Another 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.

The generators face the following additional risks: (1) Actual capital expenditure requirements over the life of the PPAs (generally 20-year terms) may be above the projected capital expenditures assumed in the contracts. The variance is not recoverable from the PPA holder. (2) There is a risk of political interference in the sense that the provincial government could step in and impose price caps. As a result of surging wholesale prices in late 2000, the Alberta government imposed an $0.11/kWh cap on electricity rates across the province. Under forthcoming regulations, the utilities will be entitled to collect from customers the difference between the utilities' prudently incurred cost of service and the price caps.

Factors Influencing Alberta Electricity Prices

Electricity prices in Alberta are being influenced by the following factors: (1) a continued strong economy, which results in growing demand for electricity; (2) minimal transmission interconnections with the other jurisdictions, which limit imports; (3) the delay in building new generation in recent years due to the uncertainty surrounding the deregulation process in Alberta; (4) the price of natural gas, as most new generation capacity is gas based.

Alberta electricity prices were high during the first four months of 2001, but they have since come down dramatically alongside the sharp decline in natural gas prices and in response to the new generation, albeit limited (245 MW), that came on line during the first half of the year. There is an additional 450 MW planned to come on line during the last four months of 2001, and a further 5,285 MW proposed over the 2002-2006 period. The significant planned new supply combined with the slowdown in the North American economy, which will have an impact on Alberta as well, will likely keep electricity prices close to their current range of $25-$50/MWh. The risk of government interference is low at present given the current price environment.

SASKATCHEWAN

Characteristics of the Saskatchewan Market

Saskatchewan Power Corporation ("SaskPower"), 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 also has 2,889 MW (853 MW hydro, 1658 MW coal, and 378MW natural gas) of generating capacity, which comprises essentially all the total installed capacity in the province. Peak energy demand has 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. SaskPower has addressed growing power needs by entering a 25-year purchase power agreement for the power from a cogeneration plant jointly owned by TransAlta Corporation and Husky Oil Limited. The 210 MW Meridian plant became operational in December 1999. Other projects currently underway include the re-powering of an existing thermal plant (Queen Elizabeth) that will increase capacity by 150 MW by July 2002, and a joint venture (with ATCO Power Ltd.) for the 228 MW Cory Cogeneration Project scheduled for commissioning in late 2002.

Interconnection: SaskPower's current export interconnection consists of 300 MW with Manitoba Hydro, 150 MW with Alberta and 150 MW with US Basin Electric. Given the costs of expanding inter-tie capacity, this situation is unlikely to change quickly. This limitation also hinders SaskPower's ability to import electricity to address power needs.

Regulation in Saskatchewan

The are currently no plans for deregulation in Saskatchewan.

On July 1, 2001, SaskPower posted an Open Access Transmission Tariff ("OATT"), which began the process of opening its transmission system to wholesale energy suppliers and users. Service bookings began on November 1. An OATT is an open offer of transmission service. This type of tariff has become the North American standard for doing business in the electrical industry. This change will secure SaskPower's direct use of the transmission systems of other electrical utilities, 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 will also have the ability to transport electricity to SaskPower's wholesale customers and to transport electricity out of the province.

MANITOBA

Characteristics of the Manitoba Market

The Manitoba Hydro-Electric Board ("Manitoba Hydro"), a wholly owned Crown corporation of the Province of Manitoba, generates, transmits and distributes electricity in the province of Manitoba. It also is the province's major distributor of natural gas through Centra Gas Manitoba. Manitoba Hydro owns and controls 97% of the generation capacity in the province (5,080 MW), with the remainder owned by Winnipeg Hydro (139 MW) and one industrial sawmill company (18 MW). Hydro-based generating capacity accounts for 95% of installed capacity (4,979 MW hydro, 249 MW gas, 9 MW oil) in the province and results in Manitoba having the lowest overall rates in Canada and the U.S. As rates across the continent continue to climb, Manitoba Hydro's customers are entering their fifth year without an increase in residential electricity rates and tenth year without an increase to large industrial electricity rates. Manitoba Hydro owns all of the transmission and distribution assets in the province except for in the City of Winnipeg, which is serviced by Winnipeg Hydro.

Some of the significant near-term capital projects that Manitoba Hydro currently has underway are: (1) conversion of its Selkirk thermal generating station from coal to natural gas in 2002 along with additional environmental upgrades; (2) construction of a 230 kV transmission line to North Dakota in 2002; and (3) construction of a 260 MW natural gas plant in Brandon, with the first of two turbines to be commissioned in mid-2002.

Interconnection: Manitoba Hydro has excellent export interconnections, equivalent to approximately 55% of installed capacity. This consists of 2,050 MW to the U.S. Mid-Continent Area Power Pool ("MAPP") power pool, 450 MW to Saskatchewan and 263 MW to Ontario. Given its extensive interconnection and the water storage capacity of its hydro-based power generating facilities, Manitoba Hydro is in an excellent position to trade power, buying low cost power during off-peak hours, and selling its own generated power during peak periods at higher rates. In the 2000/01 fiscal year, Manitoba Hydro set a record with export revenues of $480 million, 77% to the U.S. and the remainder to neighbouring provinces. Manitoba Hydro currently has long-term export contracts committing 1,410 MW of capacity in the summer months and 860 MW in the winter.

Regulation in Manitoba

The Manitoba Public Utilities Board (PUB) regulates electricity rates. 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. Rates approved for Manitoba Hydro also apply to Winnipeg Hydro. Domestic rates for large industrial customers have been voluntarily frozen since 1992 and since 1997 for residential customers, and will not be increased in 2001-02. 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 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: Power Supply, Transmission and Distribution, and Customer Service and Marketing. The structure mirrors those of other utilities who are adhering to Federal Energy Regulatory Commission ("FERC") directives in the U.S.

As a full member of the MAPP, Manitoba Hydro has greater access to American markets. Previously, all exported power was sold at the border only to neighboring utilities, which in turn delivered the power to their customers or re-sold it at a profit to other utilities. As a MAPP member, Manitoba Hydro can sell to more distant companies who then pay a toll to use the intervening transmission from the border.

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 current levels. Manitoba retail customers currently enjoy rates that are among the lowest in North America because of Manitoba Hydro's predominantly hydroelectric generation, profitable exports, and efficient resource management. Based on forecasts of the MAPP wholesale trading price, Manitoba customers would pay 30% more if domestic electricity rates were market-based.

Northern Flood Agreement (NFA) First Nation claims: Manitoba Hydro continues to address the adverse effects of its northern hydroelectric developments on five First Nation communities. The Utility has an agreement (Northern Flood Agreement) with the provincial government to assume certain obligations of the Province associated with these northern development projects. To date, four out of five native claims have reached a settlement.

ONTARIO

Background

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. The Act also gives the Ontario Energy Board ("OEB") the authority to set the rates for electricity distribution utilities in Ontario.

Under the industry restructuring, which became effective April 1, 1999, five separate entities were created from the former Ontario Hydro. (1) Ontario Power Generation Inc. ("OPG") holds and operates all the generating assets. (2) Hydro One Inc. ("HO") holds and operates all the transmission and distribution assets. (3) Ontario Electricity Financial Corporation ("OEFC") is responsible for managing and retiring the outstanding debt and certain other liabilities of the former Ontario Hydro. Maturing debt will either be repaid or refinanced directly by the Government of Ontario. (4) Independent Electricity Market Operator ("IMO") is a non-profit corporation that will perform the central market operating functions. (5) Electrical Safety Authority ("ESA") is a non-profit corporation that will conduct electric installation inspections.

As part of the restructuring, municipal electric utilities ("MEUs") must incorporate as local distribution companies ("LDCs"). In addition, they must separate ("unbundle") the distribution component ("wires") from energy marketing operations (sale of the commodity, which will be open to competition). If the shareholders of the LDCs (the municipalities) choose to operate them on a commercial basis, the LDCs will be required to make payments in lieu of income taxes ("PILs"), which will be used by the province to address the stranded debt of the former Ontario Hydro. The legislated deadline for restructuring and incorporation was November 7, 2000. The November 7, 2000 cutoff date for the transfer tax exemption remains, with minor modifications. Sales or merger agreements between MEUs had to be filed with the OEB by November 7, 2000, to be exempt from the 33% transfer tax on the proceeds from the sale. Sales and mergers require regulatory approval.

The electricity industry in Ontario was initially scheduled to be open for competition in November 2000. However, the provincial government delayed market opening as it was indicated by the Independent Electricity Market Operator and the Municipal Electric Association that the stakeholders would not be ready. *A new tentative date of May 2002 has been set by the provincial government for the market opening.* All customers in Ontario will be able to choose their supplier when the market opens.

The province's industry restructuring legislation requires that OPG decontrol (i.e., relinquish effective control through sale or lease) 4,000 MW of primarily fossil-based capacity within 42 months of open access, in addition to the decontrol of 6,200 MW of nuclear generation leased to Bruce Power through a long-term agreement. OPG has announced that it is accelerating the process through the decontrol of Lakeview (1,100 MW), Lennox (2,100 MW), Thunder Bay (300 MW) and Atikokan (200 MW), and four hydroelectric stations on the Mississagi River (500 MW). In addition, OPG is required to reduce its capacity to no more than 35% of the province's available supply (measured in MW) within ten years of market opening. The government has capped OPG's revenues at 3.8¢ per kWh on roughly two-thirds of its Ontario sales, subject to decontrol capacity reductions, for the four years following the opening up of the Ontario electricity. Any revenue in excess of the cap would be rebated pro rata to the consumers.

The OEB has set out the guidelines and procedures for establishing distribution rates for all electricity distribution utilities in Ontario, including those LDCs that remain as not-for-profit entities. With respect to the LDCs that choose to operate on a commercial basis, these guidelines and procedures: (1) define the rate base; (2) establish the new capital structure (deemed common equity and debt ratios established by OEB based on the size of the rate base); (3) set the allowed rate of return on common equity for 2001 at 9.88%; and (4) provide the formula for calculating the additional revenue requirement to achieve the target rate of return.

Subsequent to the OEB releasing the above-mentioned guidelines and procedures, a number of LDCs applied for rate increases, which were well above what the Ontario government considered to be acceptable. On June 8, 2000, the Ontario government directed the OEB to make customer protection the top priority when deciding rate applications. In addition, the Ontario government introduced legislation in June 2000 (Bill 100) to "promote efficiency in the municipal electricity sector and to protect consumers from unjustified rate increases." The legislation was never passed, but a directive was made by the province to the OEB. In response to this directive, the OEB announced on September 29, 2000, that LDCs will still be permitted to earn a market-based rate of return, but will have to phase in their additional revenue requirements evenly over three years.

There continue to be just over 90 LDCs in Ontario, with the 17 largest LDCs accounting for approximately 63% of total electricity throughputs and serving 67% of the customers. To date, Hydro One has acquired almost 90 former MEUs, most of which are in rural areas. There is currently little incentive for further mergers or acquisitions given the 33% transfer tax on the proceeds from a sale. DBRS expects the government will introduce measures to encourage more mergers in order to achieve cost efficiencies and keep electricity rates lower than they would otherwise be.

Characteristics of the Ontario Market

The Ontario market has peak demand close to 24,000 MW and total installed capacity of about 30,000 MW. However, about 5,100 MW of capacity is currently non-operational, consisting of 2,000 MW at Pickering A (expected to be operational in early 2002) and 3,100 MW at Bruce A. Therefore, at the peak, demand and supply in Ontario are currently in close balance. Ontario also has approximately 5,100 MW of interconnection capacity with Michigan, New York, Minnesota, Manitoba and Québec.

The major generators in Ontario are Ontario Power Generation with 24,700 MW (includes 2,000 MW at Pickering A currently non-operational) and Bruce Power LLP with 6,200 MW (leased from OPG – includes 3,100 MW at Bruce A currently non-operational). Other participants include Great Lakes Power with about 390 MW, and a several other independent power producers. Hydro One owns all of the transmission assets in Ontario, while the distribution assets are broadly held by Hydro One and about 90 LDCs.

Future Pricing of Electricity in Ontario

Near-Term Outlook for Electricity Prices in Ontario

Energy consultants have predicted that wholesale electricity prices in Ontario will stay at a level near 4¢ per kWh, then fall to 3.5¢ per kWh as Pickering A comes on line (scheduled for Q1 2002), and rise gradually to 4¢ per kWh by 2008 as demand load in Ontario grows at an annual rate in the 2% range (roughly 50 MW to 60 MW per year).

If environmental factors cause some coal units to curtail generation, consultants predict that prices will remain near 3.8¢ per kWh until 2004 when wholesale electricity price caps currently in place for domestic demand come off, and then rise to 4.6¢ per kWh and remain stable thereafter until about 2012.

At the retail level, electricity prices will rise over the next three years due to the key characteristics of the new environment as determined by the province. To operate on a commercial basis, the LDCs are required to re-capitalize based on an applicable deemed capital structure, make payments in lieu of taxes and will be allowed to earn a market rate of return. In the past, most were essentially non-profit organizations and had very little debt. As a result of these increased costs, rates must increase. However, the government has limited (through directives to the OEB) rate increases to a level that allows LDCs to earn a 9.88% target market rate of return on a deemed common equity. The necessary rate increases are being phased in over a three-year period.

The longer-term outlook for electricity under open market conditions is as follows:

(1) U.S. electricity prices will help establish electricity prices in Ontario, as arbitrage between the two markets occurs. The inter-ties between Ontario and the U.S. are large enough to bring some convergence between Ontario and U.S. prices. The Michigan area, which is power short in the summer, will influence power rates in Ontario in the summer. The winter power short New York market will have the greatest influence on Ontario rates in the winter. Ontario's summer demand is now essentially equal to winter demand.
(2) Initially, sales in Ontario will primarily be on a spot basis with bilateral agreements with end customers increasing over time.
(3) Prices should show substantial fluctuations between on-peak and off-peak demand, particularly at the beginning of the open market.
(4) Manitoba's limited interconnection capacity will limit competition with OPG.
(5) Hydro-Québec will have growing influence in the Ontario market as more interconnection ties are added.

Prices will be volatile when certain generators are taken out of service for maintenance, causing fluctuations in supply. The prices for electricity in Ontario will also be influenced by the value of the Canadian dollar, plus interconnection constraints. The interconnection capacity between Ontario and neighbouring markets is as follows:

	Limit on Exports (MW)	Limit on Imports (MW)	Power Pool
Michigan	2,450	1,765 in summer 1,800 in winter	ECAR
New York (at Niagara Falls)	1,950 in summer 2,050 in winter	1,450 in summer 1,750 in winter	New York Power Pool
New York (eastern Ontario)	400	400	New York Power Pool
Québec	530	1,394 in summer 1,408 in winter	
Minnesota	150	100	MAPP
Manitoba	288 in summer 300 in winter	288 in summer 300 in winter	MAPP

*Based on thermal ratings, 75% of pre-load, 0-4 km/hr wind speed, 30 Deg.C. ambient temp for summer limits and 10 Deg.C ambient temp for winter limits
**Summer limits apply from May 1 to October 31; Winter limits apply from November 1 to April 30.

QUÉBEC

Characteristics of the Québec Market

Hydro-Québec, a provincial Crown corporation, is a fully integrated utility that generates, transmits and distributes electricity to over 3.5 million customers in Québec, equivalent to about 97% of the provincial customer base. Hydro-Québec has an installed capacity of 31,512 MW (29,246 MW hydro, 1,591 MW oil and diesel, 675 MW nuclear). The Québec market has peak demand of about 34,000 MW and total installed capacity of about 41,000 MW, including about 4,000 MW from IPPs and 5,428 MW available from Churchill Falls. Approximately 1,600 MW of capacity is currently under development. Québec is a net exporter of energy with 7,395 MW of interconnection capacity, including 1,195 MW with Ontario Power Generation, 1,200 MW with New Brunswick Power, 2,305 MW with New England Utilities, and 2,695 MW into New York state.

Regulation in Quebec

In 2000, the provincial government amended the *Act respecting the Régie de l'énergie,* which included: (a) the clarification of the deregulation of generation, removing electricity generation from the Régie's jurisdiction. While generation remains unregulated, Hydro-Québec retains sole responsibility for developing sites with a capacity of over 50 MW; and (b) the establishment of a heritage electricity pool for Québec consumers. For Hydro-Québec, it means that the generator can 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 at about 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, given the low cost of power offered by Hydro-Québec, none of the other distributors in the province had exercised the option.

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.

Hydro-Québec Distribution recently submitted its electricity supply plan for the next ten years to the Régie de l'énergie to deal with the projected demand beyond the 165,000 GWh/year currently guaranteed by Hydro-Québec generation. Demand is expected to exceed the 165,000 GWh/year starting in 2006-2007. This plan and the resulting call for tenders for electricity supply should result in increased private sector generation projects in Québec and should increase competition.

The recent agreement with First Nations bands sets the stage for new hydro development in the province.

NEW BRUNSWICK

Characteristics of the New Brunswick Market

New Brunswick Power Corporation ("NB Power"), a Crown corporation, is the principle supplier of electricity in the province, supplying approximately 94% of total electricity demand. The remainder is largely made up of co-generation in the pulp and paper industry, along with some small hydro generation facilities.

The New Brunswick market has peak demand of approximately 2,900 MW and total installed capacity of 4,270 MW. New Brunswick has 2,570 MW of interconnection capacity with Hydro-Québec (1,060 MW), Nova Scotia Power Corporation (500 MW), Maritime Electric (200 MW), and New England Utilities (810 MW).

New Brunswick has among the highest interconnection ratios in Canada.

Regulation in New Brunswick

NB Power is regulated by the Board of Commissioners of Public Utilities ("PUB") 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 far below what regulated utilities in the private sector are allowed to earn.

White Paper – New Brunswick Energy Policy 2000-2010

The provincial government released its White Paper – New Brunswick Energy Policy 2000-2010 in January 2001, which outlines a managed transition to the restructuring of the electricity sector. The transition will be achieved by introducing wholesale competition and allowing non-utility generation and retail competition for large industrial customers by April 2003, while waiting until conditions prove more favourable before permitting full retail competition.

Wholesale Competition: One of the major challenges to achieving a workable competitive wholesale market is the limited size of the New Brunswick market. To achieve a workably competitive market within New Brunswick either the NB Power's generation portfolio must be broken up or the Province's transmission interconnections with adjacent markets must be significantly increased. However, breaking up NB Power's generation portfolio risks sacrificing its economies of scale, which could result in higher costs for consumers. The following are some of the key guidelines outlined in the provincial policy to address these challenges. (1) NB Power is directed to increase interconnections into the greater Northeast power market and pursue the formation of a regional transmission organization (RTO) to enhance access to neighbouring jurisdictions. (2) The economic advantage of retaining economies of scale afforded to the relatively small Crown corporation make functional unbundling (i.e., separation of transmission and generation functions) a preferred option over structural separation (i.e., three separate Crown corporation – generation, transmission and distribution). (3) The province will examine the issue of leveling the playing field between the Crown corporation and other market participants to ensure that this does not impede the development of a competitive wholesale market. (4) Currently, electricity is provided to customers through the distribution business unit of the Crown corporation and through three existing municipal utilities (Saint John, Edmundston and Perth-Andover). The province will permit the distribution electric utilities to procure power in the competitive market by a target date of April 2003. (5) The province will allow no new distribution electric utilities in New Brunswick and limit existing ones to their current service territories in order to avoid higher overall costs due to loss of economies of scale.

Non-Utility Generation Development: The province will remove current restrictions on the construction of generation facilities.

Full Retail Competition: The government's approach to full retail competition is to stage implementation starting with large industrial customers in April 2003 (i.e., with demand of greater than 750 kW), and revisiting the merits of introducing retail competition for smaller customers every two years or following pre-specified events.

NOVA SCOTIA

Characteristics of the Nova Scotia Market

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 is a wholly owned subsidiary of Emera, a diversified energy and services company. The majority of Nova Scotia Power's 2,186 MW of generation capacity is coal-based (1,272 MW), with the remainder being 381 MW of hydroelectric power, 100 MW oil, 180 MW natural gas and 250 MW of dual fuel generation. Currently, 500 MW of interconnection exists with New Brunswick, equivalent to approximately 23% of installed capacity.

Nova Scotia Power is one of the highest cost generators in Canada, even compared to other thermal-based operators. The relatively high electricity rates make Nova Scotia an attractive market to potential competitors. The other primary factor that contributes to the Utility's high cost structure is a lack of economies of scale due to a low population density in the province. This will be difficult to overcome. Prices have been stable in Nova Scotia since 1996 and will not change in 2001. However, Nova Scotia Power will become fully taxable in 2003, when most of the existing tax credits expire. The additional cost burden, if fully passed through with rate increases, would widen the competitive gap between electricity and alternative sources of energy. In spite of electricity rates that are among the highest in Canada and which could potentially attract competition, the Utility's limited interconnection capacity and isolated geographic position provide an effective barrier against new market entrants. Neighbouring utilities in the U.S. Northeast have significantly higher electricity rates and are therefore 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 they can generate higher revenues.

Regulation in Nova Scotia

The are currently no plans to deregulate in Nova Scotia.

Nova Scotia Power Inc. is regulated by the Nova Scotia Utility and Review Board ("UARB") and operates under a cost of service/rate of return methodology. Implementation of a performance-based methodology is presently under consideration (by Nova Scotia Power) and may involve a sharing of "excess earnings" mechanism. The regulatory environment is favourable and the applicable approved ROE of 10.75% has not changed since 1996. The ROE is higher than what other integrated regulated utilities are currently allowed for 2001 (in the 9.75%-10.0% range).

NEWFOUNDLAND

Characteristics of the Newfoundland Market

Newfoundland and Labrador Hydro ("NLH"), a Crown corporation of the Province of Newfoundland, generates and transmits electricity in Newfoundland and Labrador. NLH has an installed capacity of 1,602 MW (899 MW hydro, 645 MW thermal, 58 MW diesel). NLH sells approximately 65% of its output to private sector electricity distributor Newfoundland Power Inc., wholly owned by Fortis Inc., and distributes the remainder to rural customers and a small group of industrial companies. Newfoundland Power operates an integrated system of generation, transmission and distribution throughout the island portion of Newfoundland and Labrador. Newfoundland Power serves approximately 85% of all electricity customers in the province, with a peak demand of slightly over 1,000 MW. With an installed capacity of 150 MW, Newfoundland Power generates approximately 9% of its total energy needs, and the balance is purchased from NLH.

Churchill Falls (Labrador) Corporation Limited operates a 5,428 MW hydro-electric generating facility in Labrador. Under a fixed price contract that runs until 2041, roughly 90% of the power generated is sold to Hydro-Québec. Churchill Falls is 65.8% owned by Newfoundland and Labrador Hydro.

Regulation in Newfoundland

The are currently no plans to deregulate in Newfoundland and Labrador.

Newfoundland and Labrador Hydro is regulated by the Board of Commissioners of Public Utilities ("PUB"). 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. Included in the application is: (1) the establishment of the rate base; (2) a rate increase of 6.7% for Newfoundland Power and a 10.4% rate increase in industrial rates effective January 1, 2002, based largely on (a) approval to re-base the price of Bunker C fuel to \$20/barrel from \$12.50/barrel, (the price of fuel has not been changed since 1991), and (b) an ROE of 3% (and a regulated debt/equity ratio of 85/15); (3) an increase in the Rate Stabilization Plan ("RSP") cap on Newfoundland Power to \$100 million from \$50 million; and (4) a variety of other matters, including the PUB's endorsement for moving to an ROE more comparable to industry norms (and a regulated debt/equity ratio of 60/40) in the longer term. In the past, regulatory approval was required only for changes in electricity rates beyond those resulting from the recovery of the RSP balance and for capital expenditure budgets.

PRINCE EDWARD ISLAND

Characteristics of the Prince Edward Island Market

Maritime Electric, wholly owned by Fortis Inc., is the principle electric utility on PEI, serving approximately 95% of electricity customers in the province. The majority of the remainder of electricity customers are served by the City of Summerside Electric Utility. Maritime Electric owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity on PEI. 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 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.

Regulation in Prince Edward Island

The are currently no plans to deregulate in Prince Edward Island.

Under the terms of the Maritime Electric Company Limited Regulation Act, 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. In October 2001, the provincial government amended the Act to permit Maritime Electric to recover costs above an established benchmark and provide for a cost of capital adjustment mechanism.

Maritime Electric is participating in discussions with utilities based in other Maritime provinces and the state of Maine with respect to the potential formation of a Retail Transmission Organization.

Section A – Operating & Statistical Data

Table 1 (a): Installed Generating Capacity (MW)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	11,133	11,123	11,045	10,999	10,829	10,851	10,838	10,835
EPCOR	1,881	1,701	1,701	1,701	1,701	1,701	1,701	1,290
Saskatchewan Power	2,889	2,889	2,748	2,748	2,748	2,748	2,748	2,748
Manitoba Hydro	5,080	4,991	5,014	5,018	5,091	5,223	5,221	5,222
Ontario Hydro (1)	-	-	30,892	29,095	28,995	29,200	29,100	30,110
Ontario Power Generation (1)	30,819	30,819	-	-	-	-	-	-
Hydro-Quebec	31,512	31,505	31,472	31,397	31,413	31,125	30,400	29,099
N.B. Power	3,775	3,919	3,919	3,919	3,909	3,909	3,909	4,005
Nfld. & Lab. Hydro	1,602	1,602	1,602	1,602	1,602	1,601	1,601	1,602
Churchill Falls	5,428	5,428	5,428	5,428	5,428	5,428	5,428	5,428
Group Total	*94,119*	*93,977*	*93,821*	*91,907*	*91,716*	*91,786*	*90,946*	*90,339*
Investor Owned								
UtiliCorp Networks Canada (BC)	205	205	205	205	205	205	205	205
ATCO Electric (2)	1,388	1,387	1,387	1,452	1,446	1,446	1,439	1,436
TransAlta Utilities	4,476	4,476	4,471	4,471	4,471	4,471	4,471	4,471
Northern Ontario Power (3)	327	321	313	302	300	299	299	299
Nova Scotia Power	2,183	2,183	2,183	2,183	2,183	2,299	2,299	2,129
Group Total	*8,579*	*8,572*	*8,559*	*8,613*	*8,605*	*8,720*	*8,713*	*8,540*
IPPs (estimate)	5,400	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Industry Total	108,098	102,549	102,380	100,520	100,321	100,506	99,659	98,879

(1) Includes 5,136 MW of nuclear, which is currently non-operational. (2) Wholly owned by CU Inc. (3) Wholly owned by Great Lakes Power.

There has been little expansion of generation capacity over the past three years, with most of the new generation coming from independent power projects (IPPs) in Alberta, Saskatchewan and Ontario. Including the IPPs in Alberta, Saskatchewan, Ontario and Québec (about 5,400 MW), the total generation capacity in Canada stood at about 108,000 MW at the end of 2000. Most government-owned utilities are maintaining stable generation capacity, although Hydro-Québec has a 882 MW hydro project expected to come on line by the end of 2001. Ontario Power Generation, on the other hand, is in the process of reducing its capacity in Ontario through sales or leases as required by the Ontario government. Ontario Power Generation has already reduced the capacity over which it has control with the lease of its 6,200 MW Bruce nuclear plants to Bruce Power effective May 2001. Mega projects such as the Lower Churchill River project (2,000 MW) remains stalled and an agreement is not expected anytime soon.

Table 1 (b): Per cent Capacity Used - Peak Demand/Installed Capacity

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	80.8%	75.7%	79.5%	74.9%	76.3%	77.9%	75.4%	74.4%
EPCOR	N/A	61.3%	60.5%	59.3%	58.4%	61.7%	60.1%	78.3%
Saskatchewan Power	97.7%	85.2%	107.1%	107.1%	101.5%	99.9%	95.2%	95.1%
Manitoba Hydro	71.6%	70.6%	71.0%	69.5%	67.0%	68.7%	62.6%	67.3%
Ontario Hydro	-	-	71.4%	73.9%	72.1%	77.4%	75.1%	68.1%
Ontario Power Generation (1)	76.0%	76.0%	-	-	-	-	-	-
Hydro-Quebec (2)	91.4%	98.1%	99.2%	90.7%	97.2%	95.1%	102.4%	100.9%
N.B. Power	76.6%	72.9%	71.1%	71.2%	72.4%	72.3%	71.4%	69.2%
Nfld. & Lab. Hydro	77.4%	79.0%	80.8%	76.7%	82.3%	78.1%	81.5%	80.4%
Churchill Falls	103.3%	103.0%	103.2%	102.9%	102.7%	104.8%	104.3%	103.5%
Group Average	*88.7%*	*89.6%*	*88.8%*	*86.1%*	*88.0%*	*89.1%*	*90.3%*	*87.4%*
Investor Owned								
UtiliCorp Networks Canada (BC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ATCO Electric	100.9%	99.9%	102.6%	90.4%	92.0%	100.6%	91.2%	90.0%
TransAlta Utilities	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Northern Ontario Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nova Scotia Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Group Average	*16.3%*	*16.2%*	*16.6%*	*15.2%*	*15.5%*	*16.7%*	*15.1%*	*15.1%*
Industry Average	82.6%	83.4%	82.8%	80.0%	81.8%	82.8%	83.7%	81.2%

(1) Includes 5,136 MW of nuclear, which is currently non-operational. Excluding the non-operational capacity the ratio was 91.2% in 1999 & 2000.

(2) Includes contracted capacity from Churchill Falls contract.

Historically, the temperature extremes in Canada have made the differences between peak and trough demand large. This is particularly the case for utilities such as Hydro-Québec, Newfoundland & Labrador Hydro, and New Brunswick Power, which have heavy electric heating components in their sales mix. It is the weather characteristics that cause swings in power demand in Canada given the harsh and temperature-extreme climate. For example, base load for Ontario is about 16,000 MW while the twin peaks for power in January and July are close to 25,000 MW each, an almost 65% swing from peak to trough. The weather patterns across the country have a significant impact on peak demand and can cause substantial variations in the peak demand/installed capacity ratio, especially given the lack of new capacity over the past few years.

Table 2 (a): Interconnections (MW)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	3,750	3,750	3,750	3,750	2,900	2,900	2,900	2,900
EPCOR (1)	1,881	1,701	1,701	1,701	1,701	1,701	1,701	1,290
Saskatchewan Power	600	600	600	600	600	600	600	600
Manitoba Hydro	2,763	2,740	2,740	2,440	2,440	2,440	2,440	2,440
Ontario Hydro	-	-	4,740	4,740	4,740	4,740	4,740	4,740
Ontario Power Generation	5,830	5,830	-	-	-	-	-	-
Hydro-Quebec (2)	7,395	7,393	7,393	7,520	7,520	7,520	7,520	7,487
N.B. Power	2,570	2,570	2,570	2,570	2,570	2,570	2,570	2,570
Nfld. & Lab. Hydro	0	0	0	0	0	0	0	0
Churchill Falls	5,428	5,428	5,428	5,428	5,428	5,428	5,428	5,428
Group Total	*30,217*	*30,012*	*28,922*	*28,749*	*27,899*	*27,899*	*27,899*	*27,455*
Investor Owned								
UtiliCorp Networks Canada (BC)	205	205	205	205	205	205	205	205
ATCO Electric (1)	1,312	1,388	1,387	1,452	1,446	1,446	1,439	1,436
TransAlta Utilities (1)	4,476	4,476	4,471	4,471	4,471	4,471	4,471	4,471
Northern Ontario Power	327	321	313	302	300	299	299	299
Nova Scotia Power	500	500	500	500	500	500	500	500
Group Total	*6,820*	*6,890*	*6,876*	*6,930*	*6,922*	*6,921*	*6,914*	*6,911*
Industry Total	37,037	36,902	35,798	35,679	34,821	34,820	34,813	34,366

(1) Represents interconnections to Alberta Power Pool.

(2) Total simultaneous interconnections - 6,497.

There is very little new interconnection capacity being built, except the 1,250 MW line proposed between Ontario and Quebec and the improvement to the interconnection between Ontario and Michigan, which will raise the export capacity by 1,000 MW. The 37,000 MW of interconnection capacity is about one-third of the 108,000 MW of total generation capacity that exists in Canada. There is little east/west interconnection in Canada, with much of the interconnection being north/south with the U.S. Not all this interconnection capacity can be used at the same time, so effective capacity is about 10%-20% below the levels shown.

Table 2 (b): Percentage of Generating Capacity Interconnected

	Interconnections	Installed Capacity	% Interconnected
Government Owned	(MW)	(MW)	(Percentage)
B.C. Hydro	3,750	11,133	33.7%
EPCOR	1,881	1,881	100.0%
Saskatchewan Power	600	2,889	20.8%
Manitoba Hydro	2,763	5,080	54.4%
Ontario Power Generation	5,830	30,819	18.9%
Hydro-Quebec	5,830	30,819	18.9%
N.B. Power	7,395	31,512	23.5%
Nfld. & Lab. Hydro	2,570	3,775	68.1%
Churchill Falls	0	1,602	0.0%
Group Total / Average	*30,217*	*94,119*	*32.1%*
Investor Owned			
UtiliCorp Networks Canada (BC)	205	205	100.0%
ATCO Electric	1,312	1,388	94.5%
TransAlta Utilities	4,476	4,476	100.0%
Northern Ontario Power	327	327	100.0%
Nova Scotia Power	500	2,183	22.9%
Group Total / Average	*6,820*	*8,579*	*79.5%*
Industry Total / Average	37,037	108,098	34.3%

Manitoba Hydro and N.B. Power continue to have the highest proportion of their capacity interconnected with other utilities. Approval for new interconnection capacity generally takes a long time. The new 1,250 MW line between Ontario and Quebec is proceeding, albeit very slowly. The lack of interconnections means that Canadian utilities must ensure they have enough generation capacity directly, and it reduces their ability to become active exporters and take advantage of selling electricity at higher prices prevailing in other jurisdictions.

Table 3: 2000 Generation Mix (based on 2000 installed capacity)

Government Owned	BC Hydro	EPCOR Power	Sask. Power	Manitoba Hydro	Ontario Power	Hydro Quebec	N.B. Power	Nfld & Lab Hydro	Churchill Falls	*Group Average*
Coal	-	48.2%	57.4%	-	24.5%	-	13.1%	40.3%	-	*11.9%*
Gas	8.2%	51.8%	13.1%	4.7%	3.5%	-	-	-	-	*3.7%*
Hydro	89.8%	-	29.5%	95.2%	23.5%	92.8%	22.6%	56.1%	100.0%	*63.1%*
Nuclear	-	-	-	-	45.0%	2.1%	16.2%	-	-	*16.1%*
Oil *	1.9%	-	-	0.2%	3.5%	5.1%	53.2%	3.6%	-	*5.4%*
Installed Capacity	*11,123*	*1,701*	*2,889*	*4,991*	*30,819*	*31,505*	*3,919*	*1,602*	*5,428*	*93,977*

Investor Owned	UtiliCorp Networks Canada (BC)	ATCO Electric	TransAlta Utilities	Great Lakes	N.S. Power	*Group Average*
Coal	-	86.9%	82.1%	-	58.3%	*71.8%*
Gas	-	7.8%	-	-	8.2%	*3.4%*
Hydro	100.0%	-	17.8%	100.0%	17.5%	*19.9%*
Nuclear	-	-	-	-	-	-
Oil	-	5.4%	-	-	16.0%	*5.0%*
Installed Capacity	*205*	*1,387*	*4,476*	*321*	*2,183*	*8,572*

* Includes Orimulsion

The generation mixes for the various utilities have remained relatively stable over the past three years. B.C. Hydro, Hydro-Québec and Manitoba Hydro continue to get over 90% of their electricity from hydro. N.B. Power is the main oil-based generation utility. The private sector remains heavily coal-based, although the smaller utilities are entirely hydro-based. 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.

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 Electric Generated - millions kWh

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	49,940	51,646	50,677	51,779	53,828	45,262	43,798	43,411
EPCOR	10,775	9,863	10,605	8,848	9,113	8,628	8,803	5,977
Saskatchewan Power	16,451	17,285	17,600	17,429	17,109	16,925	16,002	15,733
Manitoba Hydro	31,567	29,044	29,252	33,107	30,909	28,357	27,168	26,466
Ontario Hydro	-	-	125,980	131,017	134,278	137,855	141,564	133,281
Ontario Power Generation	136,000	131,101	-	-	-	-	-	-
Hydro-Quebec	145,960	142,400	131,700	141,726	147,692	150,408	140,471	131,552
N.B. Power	18,818	17,123	20,099	17,242	14,795	12,950	14,667	14,841
Nfld. & Lab. Hydro	6,025	5,756	5,556	6,197	6,047	6,000	5,908	6,088
Churchill Falls	35,250	34,611	37,651	33,878	29,103	30,072	30,756	33,059
Group Total	*450,786*	*438,829*	*429,120*	*441,223*	*442,874*	*436,457*	*429,137*	*410,408*
Investor Owned								
UtiliCorp Networks Canada (BC)	1,489	1,494	1,507	1,549	1,425	1,545	1,565	1,530
ATCO Electric	8,724	8,527	8,904	9,029	8,220	8,989	9,494	9,412
TransAlta Utilities	28,122	28,717	29,769	30,353	29,598	29,812	29,311	29,039
Northern Ontario Power	1,369	1,503	969	1,484	1,801	1,381	1,352	1,733
Nova Scotia Power	11,137	10,668	10,264	9,963	9,571	9,176	9,377	9,340
Group Total	*50,841*	*50,909*	*51,413*	*52,378*	*50,615*	*50,903*	*51,099*	*51,054*
Industry Total	501,627	489,738	480,533	493,601	493,489	487,360	480,236	461,462

Electricity generated has typically been influenced by: (1) the amount of rainfall for B.C. Hydro, Hydro-Québec and Manitoba Hydro; (2) the state of Ontario's nuclear facilities (there was no change in 2000); and (3) the amount of new generation capacity. In 2000, there was only a limited impact from these three variables. However, over the 2002-2004 period, electricity generation will be influenced by: (1) the 2,000 MW of generation capacity from Pickering A and 1,500 MW of capacity from Bruce A coming back on line; (2) several smaller cogeneration projects in Alberta, Saskatchewan and Ontario; (3) improvements to existing generators, which will add small amounts of capacity; and (4) Hydro's-Québec's 882 MW hydro-based generator coming on line.

Table 4 (b): Gross Power Purchases - millions kWh

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	27,291	23,299	19,100	9,296	5,950	5,921	7,450	5,567
EPCOR	0	0	0	0	0	0	0	505
Saskatchewan Power	3,686	1,811	1,536	982	741	291	595	520
Manitoba Hydro	905	1,004	1,935	168	169	401	200	705
Ontario Hydro	-	-	16,992	13,750	9,252	8,386	5,938	4,980
Ontario Power Generation	0	0	-	-	-	-	-	-
Hydro-Quebec (1)	25,793	11,307	10,200	4,006	3,451	2,899	3,438	3,397
N.B. Power	2,092	4,712	2,568	3,148	3,908	6,274	3,559	2,058
Nfld. & Lab. Hydro	2,545	2,538	2,393	932	878	838	845	723
Churchill Falls	0	0	0	0	0	0	0	0
Group Total	*66,112*	*50,470*	*54,724*	*32,282*	*24,349*	*25,010*	*22,025*	*18,455*
Investor Owned								
UtiliCorp Networks Canada (BC)	1,538	1,468	1,414	1,414	1,685	1,443	1,419	1,490
ATCO Electric	1,393	1,418	1,167	989	1,334	620	(154)	(405)
TransAlta Utilities	514	561	534	557	501	680	401	0
Northern Ontario Power	993	921	1,481	931	572	799	766	413
Nova Scotia Power	295	411	242	340	255	500	216	219
Group Total	*4,733*	*4,779*	*4,838*	*4,231*	*4,347*	*4,042*	*2,648*	*1,717*
Industry Total	70,845	55,249	59,562	36,513	28,696	29,052	24,673	20,172

(1) Excludes Churchill Falls Purchases

Gross power purchased is growing due to: (1) increased trading/exporting, particularly for B.C. Hydro and Hydro-Québec; and (2) tight supply/demand conditions, as is the case for Saskatchewan Power.

Power purchase is a “trading” function for most Canadian electric utilities who, 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. As RTOs develop in the U.S., the hydro-based Canadian electric utilities will conserve water during the off-peak periods and buy “cheap” electricity from the U.S. During peak periods (i.e., rush hour in New York), the Canadian electric utilities will produce at 100% capacity. This strategy raises the average price received for export power.

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

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	6.7%	6.8%	7.6%	7.6%	8.9%	8.5%	8.3%	8.8%
EPCOR	7.1%	7.3%	7.0%	7.5%	8.9%	10.7%	10.5%	10.6%
Saskatchewan Power	15.3%	15.0%	15.4%	15.2%	15.6%	16.5%	16.7%	15.4%
Manitoba Hydro	11.3%	11.2%	11.2%	11.5%	11.3%	11.5%	11.7%	11.3%
Ontario Hydro	-	-	2.8%	3.5%	4.0%	3.7%	4.0%	4.1%
Ontario Power Generation	n.a.	n.a.	-	-	-	-	-	-
Hydro-Quebec	7.8%	8.7%	10.3%	9.3%	8.9%	9.1%	9.1%	9.5%
N.B. Power	9.7%	9.1%	9.1%	8.9%	10.2%	9.8%	10.2%	10.6%
Nfld. & Lab. Hydro	4.2%	3.7%	4.4%	4.9%	4.9%	4.9%	5.8%	5.2%
Churchill Falls	1.8%	2.3%	2.1%	2.2%	2.4%	2.1%	2.0%	2.0%
Group Average	*5.6%*	*5.8%*	*7.1%*	*7.0%*	*7.4%*	*7.3%*	*7.3%*	*7.4%*
Investor Owned								
UtiliCorp Networks Canada (BC)	10.2%	10.7%	10.4%	11.3%	11.3%	12.2%	12.5%	11.3%
ATCO Electric	1.3%	2.8%	2.8%	3.3%	2.1%	11.6%	11.4%	13.7%
TransAlta Utilities	n.a.	5.9%	8.7%	7.9%	7.5%	6.9%	7.6%	7.3%
Northern Ontario Power	2.2%	3.4%	2.9%	4.2%	4.3%	2.5%	2.5%	4.7%
Nova Scotia Power	6.8%	6.4%	7.0%	7.6%	6.9%	6.6%	6.5%	7.0%
Group Average	*2.3%*	*5.6%*	*7.2%*	*7.1%*	*6.5%*	*7.8%*	*8.2%*	*8.4%*
Industry Average	5.3%	5.8%	7.1%	7.0%	7.3%	7.3%	7.4%	7.5%

Average power used and lost in transmission averaged just over 5% in 2000, down from previous years due entirely to changes in the reporting of gross and net generation by Ontario Power Generation and TransAlta Utilities. About 2%-4% is lost in distribution. Transmission losses remain highest for Saskatchewan Power, Manitoba Hydro and UtiliCorp Networks Canada (BC). Canada’s long distances with generation in the north and consumption in the south, raises the degree of line losses. Saskatchewan losses are related to the nature of the transmission grid and the extremely low population density of the province. Almost half the population lives in two cities, leaving the rest of the province with extremely low population density.

Table 5 (a): Electricity Sales - million kWh

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	72,031	69,852	64,506	56,460	54,484	46,822	46,981	44,663
EPCOR	10,013	9,147	9,858	8,180	8,305	7,703	7,875	5,792
ENMAX (1)	7,500	7,162	6,980	6,867	6,644	-	-	-
Saskatchewan Power	17,049	16,225	16,187	15,608	15,064	14,383	13,820	13,748
Manitoba Hydro	28,734	26,688	27,692	29,462	27,567	25,460	24,165	24,103
Ontario Hydro	-	-	138,914	139,727	137,770	140,850	141,656	132,594
Ontario Power Generation	139,800	136,900	-	-	-	-	-	-
Hydro One (1)	17,600	18,100	-	-	-	-	-	-
Hydro-Quebec	190,080	171,712	161,373	162,533	163,546	166,101	158,166	152,099
N.B. Power	18,889	19,842	20,597	18,577	16,804	17,338	16,361	15,110
Nfld. & Lab. Hydro	8,206	7,988	7,598	6,781	6,589	6,506	6,364	6,457
Churchill Falls	34,601	33,807	36,878	33,131	28,411	29,450	30,150	32,398
Group Total (2)	*487,641*	*460,756*	*449,466*	*440,158*	*432,793*	*427,919*	*418,125*	*397,055*
Investor Owned								
UtiliCorp Networks Canada (BC)	2,717	2,646	2,617	2,628	2,759	2,623	2,611	2,680
ATCO Electric	9,983	9,668	9,790	9,687	9,351	8,493	8,206	7,770
TransAlta Utilities	28,636	27,560	27,672	28,463	27,844	28,380	27,450	25,819
Northern Ontario Power	2,309	2,341	2,378	2,313	2,270	2,125	2,064	2,044
Nova Scotia Power	10,656	10,365	9,772	9,516	9,146	9,035	8,966	8,894
Group Total	*54,301*	*52,580*	*52,229*	*52,607*	*51,369*	*50,656*	*49,297*	*47,207*
Industry Total (2)(3)	541,942	513,336	501,695	492,765	484,162	478,575	467,421	444,262
Industry Growth	5.6%	2.3%	1.8%	1.8%	1.2%	2.4%	5.2%	2.1%

(1) Represents distribution sales. Excluded from all totals.

(2) Excludes Churchill Falls + N&L exports to Hydro-Quebec. (3) Totals incorporate some double-counting.

Electricity sales across Canada have typically grown at about 2% per year, although sales jumped sharply in 2000, due to both increased export sales, but also strong domestic sales as a result of the strong economic growth. In a given year, weather plays an important role given Canada's winter/ summer extremes in temperature. With about 60% of generation having a hydro base, any one utility's output is influenced by rainfall in that year. Hydro-Québec accounted for most of the growth in 2000 due to both increased energy trading, but also increased production related to the availability of water.

Table 5 (b): Exports as a Per cent of Electricity Sold

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	33.2%	33.5%	29.0%	23.3%	18.0%	5.2%	8.4%	5.9%
EPCOR	34.3%	31.6%	37.3%	26.1%	27.8%	23.5%	24.5%	0.0%
Saskatchewan Power	14.0%	12.3%	11.2%	9.8%	10.8%	3.4%	1.4%	4.7%
Manitoba Hydro	42.0%	40.9%	41.2%	46.0%	41.7%	37.9%	39.0%	37.8%
Ontario Hydro	-	-	2.2%	4.6%	4.4%	6.5%	8.9%	3.6%
Ontario Power Generation	2.9%	3.3%	-	-	-	-	-	-
Hydro-Quebec	19.6%	14.4%	11.5%	9.4%	11.6%	14.5%	12.1%	9.9%
N.B. Power	25.8%	31.5%	34.2%	25.7%	21.1%	23.9%	23.2%	16.2%
Nfld. & Lab. Hydro	18.2%	21.7%	17.7%	0.0%	0.0%	0.0%	0.0%	0.0%
Churchill Falls	87.5%	87.8%	88.9%	91.5%	90.6%	90.6%	90.9%	92.3%
Group Average (1)	*19.5%*	*17.5%*	*15.6%*	*13.9%*	*13.3%*	*13.0%*	*13.1%*	*9.5%*

(1) Excludes Churchill Falls and Nfld & Lab sales to Hydro-Quebec, which in turn exports to U.S. Markets. EPCOR exports represent sale of surplus power to Alberta Power Pool.

Exports are growing as RTOs in the U.S. provide Canadian electric utilities with increased access to the U.S. markets.

Table 6 (a): Electricity Revenues - $ millions

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	7,830	3,427	2,997	2,497	2,377	2,233	2,259	2,156
EPCOR (1)	1,113	841	821	787	770	527	485	386
ENMAX (2)	689	478	460	445	434	-	-	-
Saskatchewan Power	1,080	957	940	902	871	837	821	788
Manitoba Hydro	1,261	1,113	1,074	1,036	1,018	981	937	918
Ontario Hydro	-	-	8,672	8,609	8,579	8,679	8,728	8,360
Ontario Power Generation (3)	5,855	5,579	-	-	-	-	-	-
Hydro One (4)	2,963	3,030	-	-	-	-	-	-
Hydro-Quebec	10,174	8,499	8,007	7,927	7,655	7,576	7,259	6,997
N.B. Power	1,263	1,218	1,176	1,114	1,007	988	915	869
Nfld. & Lab. Hydro	302	316	303	292	287	285	280	286
Churchill Falls (5)	96	93	94	87	80	84	82	87
Group Total	*32,625*	*25,551*	*24,544*	*23,695*	*23,077*	*22,190*	*21,766*	*20,846*
Investor Owned								
UtiliCorp Networks Canada (BC)	135	125	123	123	125	117	107	110
ATCO Electric (1)	734	644	620	609	600	611	595	569
TransAlta Utilities (1)	742	1,130	1,114	1,069	1,151	1,114	1,120	1,104
Northern Ontario Power	124	125	127	124	123	114	109	109
Nova Scotia Power	813	790	751	741	731	712	708	700
Group Total	*2,548*	*2,815*	*2,735*	*2,666*	*2,730*	*2,668*	*2,640*	*2,591*
Industry Total	35,173	28,366	27,278	26,361	25,806	24,859	24,406	23,437
Industry Growth	24.0%	4.0%	3.5%	2.1%	3.8%	1.9%	4.1%	5.0%

(1) Net of AEEMA/ASPRDA. (2) Distribution only. (3) Generation only. (4) Transmission and distribution. (5) Includes sales to Hydro-Quebec.

Electricity revenue growth has been restricted by rate freezes in effect in most provinces, although domestic sales increased just over 3% in 2000, helping to offset some of the negative impact of the rate freeze. The primary contributors to the sharp increase in electricity revenue in 2000 were the higher export prices and the 12.9% in the volume of electricity exported. This had a particularly large impact on B.C. Hydro and Hydro-Québec revenues. The higher electricity prices were due to: (1) a lack of construction of new generation capacity in the U.S.; (2) higher fuel costs, which makes hydro-based electricity much more competitive; and (3) growing demand helped by strong economic growth and the growth in electricity-intensive high tech applications such as Web-hosting.

Table 6 (b): Exports as a Per cent of Electricity Revenues

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	69.7%	32.9%	24.7%	13.7%	6.9%	2.3%	6.3%	4.4%
EPCOR (1)	61.6%	50.7%	49.7%	47.2%	46.6%	7.5%	8.9%	0.0%
Saskatchewan Power	16.7%	9.6%	7.7%	6.3%	6.5%	0.9%	0.5%	1.4%
Manitoba Hydro	38.1%	33.8%	30.4%	28.7%	26.3%	25.0%	27.0%	25.2%
Ontario Hydro	-	-	1.7%	2.0%	2.0%	2.7%	4.0%	1.5%
Ontario Power Generation	4.8%	4.2%	-	-	-	-	-	-
Hydro One	-	-	-	-	-	-	-	-
Hydro-Quebec	23.4%	12.4%	10.2%	7.5%	7.7%	8.4%	7.1%	6.4%
N.B. Power	26.3%	27.1%	25.9%	21.9%	18.0%	18.9%	17.9%	15.6%
Nfld. & Lab. Hydro	4.4%	12.2%	9.9%	0.0%	0.0%	0.0%	0.0%	0.0%
Churchill Falls	92.3%	92.0%	92.8%	95.6%	95.2%	95.5%	95.3%	95.6%
Group Average (2)	*30.3%*	*14.7%*	*11.9%*	*9.1%*	*8.1%*	*6.7%*	*7.1%*	*5.4%*

(1) Represents sale of surplus power to the Alberta Power Pool.

(2) Totals incorporate some double-counting, i.e., Churchill Falls exports to Hydro-Quebec, which Hydro-Quebec in turn exports to U.S.

Export revenue continued to grow in 2000, with BC Hydro in particular experiencing a very large increase.

Table 7: Total Assets - $ millions

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	12,615	11,596	11,685	11,305	11,456	12,124	12,463	11,998
EPCOR	3,050	2,357	2,229	2,194	2,122	1,786	1,820	1,803
ENMAX	1,130	540	545	517	509	-	-	-
Saskatchewan Power	3,332	3,203	3,230	3,249	3,332	3,334	3,270	3,230
Manitoba Hydro	8,962	8,692	7,866	7,617	7,133	6,737	6,449	6,543
Ontario Hydro	-	-	40,023	39,181	39,870	42,984	44,085	44,706
Ontario Power Generation (1)	16,791	15,610	-	-	-	-	-	-
Hydro One (1)	9,997	10,090	-	-	-	-	-	-
Hydro-Quebec	59,111	56,836	57,295	55,194	53,760	53,755	51,608	47,879
N.B. Power	3,470	3,465	3,666	4,197	4,287	4,377	4,344	4,359
Nfld. & Lab. Hydro	1,817	1,802	1,892	1,901	1,958	2,069	1,999	1,604
Churchill Falls	676	693	741	751	771	794	737	751
Group Total	*120,951*	*114,883*	*129,172*	*126,106*	*125,198*	*127,959*	*126,776*	*122,872*
Investor Owned								
UtiliCorp Networks Canada (BC)	367	335	308	292	278	265	258	209
ATCO Electric	2,221	2,035	2,033	1,997	1,986	1,964	1,938	1,923
TransAlta Utilities	3,040	3,309	3,272	3,384	3,573	3,670	3,745	3,901
Northern Ontario Power	782	772	771	740	752	424	420	418
Nova Scotia Power	2,839	2,812	2,827	2,881	3,065	3,144	3,129	3,059
Group Total	*9,249*	*9,264*	*9,210*	*9,293*	*9,654*	*9,466*	*9,490*	*9,509*
Industry Total	130,199	124,147	138,382	135,399	134,852	137,425	136,266	132,382

(1) Ontario Hydro was restructured in April 1999. Generation transferred (to OPG) at book value. Transmission and distribution (to Hydro One) at book value.

Total assets are currently around $130 billion and have typically grown at a very slow pace. The increase in 2000 came primarily from Hydro-Québec as a result of its ongoing major capital expenditure program and the $1.6 billion acquisition of Transelec, the largest transmission company in Chile. Hydro-Québec, with assets near $60 billion, is by far the largest electric utility in Canada. However, the differential in size between Hydro-Québec and Ontario Power Generation is somewhat misleading as Ontario Power Generation wrote off $14 billion in assets in 1999 as a result of nuclear-related problems.

Table 8: Accumulated Depreciation/Gross Fixed Assets

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	36.0%	34.8%	33.6%	32.5%	31.3%	30.2%	29.0%	28.1%
EPCOR	27.7%	26.5%	26.7%	25.5%	23.5%	19.6%	19.1%	17.5%
ENMAX	43.4%	43.6%	43.1%	38.4%	37.3%	-	-	-
Saskatchewan Power	38.9%	37.5%	36.0%	34.3%	32.6%	30.5%	28.4%	27.1%
Manitoba Hydro	28.9%	27.7%	27.7%	26.8%	25.8%	25.1%	24.1%	22.9%
Ontario Hydro	-	-	31.4%	29.3%	27.0%	24.4%	21.9%	19.5%
Ontario Power Generation (1)	6.6%	2.9%	-	-	-	-	-	-
Hydro One (1)	32.5%	31.5%	-	-	-	-	-	-
Hydro-Quebec	24.1%	22.9%	21.3%	19.8%	18.1%	16.6%	15.5%	14.6%
N.B. Power	45.4%	42.8%	40.0%	37.2%	31.6%	29.0%	27.2%	25.3%
Nfld. & Lab. Hydro	23.2%	22.1%	21.0%	19.4%	17.9%	16.5%	15.1%	13.7%
Churchill Falls	40.2%	38.6%	36.8%	35.1%	33.4%	31.7%	30.0%	28.6%
Group Average	*26.4%*	*25.0%*	*27.6%*	*26.0%*	*24.1%*	*22.2%*	*20.5%*	*19.1%*
Investor Owned								
UtiliCorp Networks Canada (BC)	29.2%	29.8%	30.0%	30.4%	29.6%	28.9%	28.7%	34.0%
ATCO Electric	38.4%	37.3%	35.9%	34.4%	32.7%	30.8%	29.0%	27.0%
TransAlta Utilities	46.1%	49.0%	47.8%	45.7%	43.9%	41.5%	38.7%	35.4%
Northern Ontario Power	20.5%	19.3%	17.8%	16.5%	15.1%	26.5%	25.4%	24.6%
Nova Scotia Power	34.5%	33.1%	31.9%	30.8%	29.8%	28.5%	27.0%	25.4%
Group Average	*38.8%*	*40.1%*	*38.9%*	*37.3%*	*36.0%*	*35.0%*	*32.9%*	*30.7%*
Industry Average	27.5%	26.4%	28.6%	26.9%	25.1%	23.2%	21.5%	20.0%

(1) Ontario Hydro was restructured in April 1999. Generation transferred (to OPG) at book value. Transmission and distribution (to Hydro One) at book value.

The accumulated depreciation/gross fixed assets ratio shows the proportion of gross assets, which have been expensed. The ratio is rising about 1 percentage point per year per company, except for Ontario Power Generation due to the large asset write-offs in 1999. The older, more mature utilities that experienced slower expansion during the 1990s, such as TransAlta Utilities, N.B. Power, Churchill Falls, Saskatchewan Power, ATCO Electric and B.C. Hydro have depreciated close to 40% or more of their assets. The faster growing utilities, such as Hydro-Québec, have a much lower proportion of their asset base depreciated. In addition, hydro-based generation has lower depreciation rates than coal, and Hydro-Québec is one of the few Canadian electric utilities that expanded generation in the 1990s.

Section B – Financial Ratios

Table 9 (a): % Debt in the Capital Structure (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	82.5%	83.5%	85.2%	85.3%	86.1%	87.0%	87.5%	87.1%
EPCOR	65.7%	61.1%	60.7%	62.3%	64.6%	67.5%	71.5%	74.6%
ENMAX	60.9%	30.5%	33.4%	38.1%	32.4%	-	-	-
Saskatchewan Power	55.7%	56.3%	58.9%	61.0%	64.3%	67.2%	67.8%	68.9%
Manitoba Hydro	85.3%	88.1%	89.5%	90.8%	92.4%	93.8%	95.0%	96.1%
Ontario Hydro	-	-	111.3%	117.1%	92.6%	87.9%	89.9%	91.4%
Ontario Power Generation	38.1%	38.7%	-	-	-	-	-	-
Hydro One	53.5%	54.6%	-	-	-	-	-	-
Hydro-Quebec	73.6%	73.5%	74.8%	74.8%	75.6%	76.6%	76.5%	76.1%
N.B. Power	99.7%	99.3%	99.9%	88.6%	88.3%	88.0%	88.0%	88.4%
Nfld. & Lab. Hydro	66.4%	63.1%	65.2%	68.1%	69.4%	70.1%	70.3%	69.6%
Churchill Falls	46.7%	49.5%	53.8%	55.2%	56.4%	58.1%	55.5%	57.1%
Group Average	*69.8%*	*70.0%*	*85.6%*	*86.9%*	*82.1%*	*81.8%*	*82.7%*	*83.5%*
Investor Owned								
UtiliCorp Networks Canada (BC)	62.4%	59.1%	61.3%	59.1%	58.9%	56.8%	58.2%	51.3%
ATCO Electric	55.8%	53.2%	55.2%	58.7%	60.8%	63.8%	66.8%	62.7%
TransAlta Utilities	57.0%	51.7%	48.1%	49.6%	47.9%	52.9%	50.0%	50.3%
Northern Ontario Power	34.5%	34.6%	34.6%	32.8%	32.4%	61.5%	61.6%	62.5%
Nova Scotia Power	65.4%	65.8%	67.2%	67.8%	69.0%	68.7%	69.2%	69.5%
Group Average	*57.4%*	*55.0%*	*54.8%*	*56.0%*	*56.5%*	*60.9%*	*60.5%*	*59.4%*
Industry Average	68.8%	68.7%	83.4%	84.6%	80.2%	80.4%	81.2%	81.7%

(1) Sinking funds netted against debt. Includes debt equivalents. Preferred shares and minority interest have been classified as either debt or equity equivalents.

Government-owned utilities continue to be more highly leveraged, with some utilities having over 80% debt in the capital structure. Given that most government-owned utilities have not had any major capital expansion projects (except for Hydro-Québec), the strong free cash flow has been available to pay down debt. In addition, the improved fiscal performance by most provinces has reduced the need to have the utilities pay out large dividends. As a result of these factors and the restructuring of Ontario Hydro in 1999, which created two companies with strong balance sheets, leverage has been generally declining for government-owned utilities.

Investor-owned utilities continue to have leverage closer to 60%, with the fluctuations from year to year largely due to working capital requirements related to the distribution and transmission businesses.

Table 9 (b): Average Coupon on Long-Term Debt

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	7.80%	8.10%	7.70%	8.50%	8.50%	9.40%	10.00%	10.10%
EPCOR	9.14%	9.59%	10.27%	10.29%	10.26%	10.28%	10.27%	10.37%
ENMAX	7.77%	9.04%	9.08%	9.34%	10.11%	-	-	-
Saskatchewan Power	8.95%	9.11%	9.20%	9.34%	9.47%	9.62%	9.54%	9.53%
Manitoba Hydro	8.38%	8.56%	8.38%	8.79%	8.74%	9.22%	8.49%	8.41%
Ontario Hydro	-	-	9.30%	9.30%	9.50%	9.90%	10.00%	10.20%
Ontario Power Generation	5.93%	5.93%	-	-	-	-	-	-
Hydro One	8.13%	7.70%	-	-	-	-	-	-
Hydro-Quebec	8.82%	8.71%	8.80%	8.91%	9.13%	9.40%	9.69%	9.60%
N.B. Power	8.39%	8.88%	9.07%	9.06%	9.07%	9.13%	9.20%	9.20%
Nfld. & Lab. Hydro	8.40%	8.38%	8.73%	9.51%	10.10%	10.10%	10.80%	10.60%
Churchill Falls	7.71%	7.71%	7.71%	7.70%	7.70%	7.72%	7.71%	7.71%
Group Average	*8.38%*	*8.42%*	*8.84%*	*8.90%*	*9.06%*	*9.56%*	*9.75%*	*9.79%*
Investor Owned								
UtiliCorp Networks Canada (BC)	7.96%	8.18%	8.85%	8.76%	9.26%	9.50%	10.50%	10.70%
ATCO Electric	9.49%	9.59%	9.91%	9.93%	10.10%	10.17%	10.47%	10.80%
TransAlta Utilities	7.21%	7.78%	8.16%	8.78%	9.32%	9.34%	9.56%	9.97%
Northern Ontario Power	6.62%	6.62%	6.62%	6.69%	6.69%	11.88%	11.88%	11.88%
Nova Scotia Power	7.59%	7.58%	7.99%	8.03%	8.15%	8.74%	9.59%	9.94%
Group Average	*7.90%*	*8.08%*	*8.42%*	*8.67%*	*8.95%*	*9.46%*	*9.95%*	*10.26%*
Industry Average	8.35%	8.40%	8.82%	8.89%	9.06%	9.56%	9.76%	9.81%

The average coupon rate on long-term debt continues to fall as high coupon debt is paid down and refinanced at the current low interest rates. High coupon debt is being called where possible. 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. ATCO Electric and EPCOR in particular continue to face high average coupon rates on the debt. It is expected that utilities' average coupon rates will continue to decline over time given the low interest rate environment. However, it will take time to bring the average rate down significantly given the generally long average term to maturity of utility debt and the high costs associated with calling high coupon debt.

Table 10 (a): EBIT Interest Coverage (times) (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	2.40	1.91	1.64	1.65	1.47	1.18	1.21	1.19
EPCOR	1.98	1.84	1.92	1.82	1.81	1.74	1.38	0.80
ENMAX	2.62	3.98	5.15	4.59	2.40	-	-	-
Saskatchewan Power	1.85	1.86	1.79	1.68	1.69	1.37	1.41	1.36
Manitoba Hydro	1.52	1.30	1.19	1.22	1.21	1.15	1.13	1.12
Ontario Hydro	-	-	1.39	1.13	1.23	1.22	1.25	0.91
Ontario Power Generation	7.53	4.96	-	-	-	-	-	-
Hydro One	2.50	2.45	-	-	-	-	-	-
Hydro-Quebec	1.28	1.24	1.18	1.22	1.11	1.06	1.07	1.04
N.B. Power	1.05	1.12	1.13	0.92	0.79	0.74	0.81	0.91
Nfld. & Lab. Hydro	1.17	1.51	1.45	1.24	1.17	1.19	1.11	1.14
Churchill Falls	1.73	1.75	1.68	1.53	1.46	1.50	1.44	1.56
Group Average	*1.72*	*1.59*	*1.33*	*1.24*	*1.21*	*1.14*	*1.16*	*1.01*
Investor Owned								
UtiliCorp Networks Canada (BC)	2.27	2.20	2.22	2.70	2.72	2.48	2.05	2.68
ATCO Electric	2.94	3.01	3.19	3.01	2.89	2.90	2.96	2.95
TransAlta Utilities	2.49	2.78	3.59	3.19	4.02	3.75	3.71	3.81
Northern Ontario Power	2.34	2.81	1.44	2.06	2.20	2.19	1.94	2.61
Nova Scotia Power	2.30	2.28	2.08	2.07	1.89	1.75	1.63	1.37
Group Average	*2.53*	*2.65*	*2.85*	*2.70*	*2.85*	*2.67*	*2.59*	*2.47*
Industry Average	1.79	1.67	1.41	1.32	1.30	1.23	1.24	1.08

(1) Before capitalized interest, AFUDC, debt amortizations and retractable preferred dividends.

EBIT coverage for government-owned utilities continued to improve in 2000 entirely due to operating income growth, as interest costs remained relatively stable in 2000. For investor-owned utilities, however, EBIT interest coverage declined in 2000, with most of the deterioration coming from TransAlta Utilities. Most of the government-owned utilities are protected by provincial guarantees (except for EPCOR Utilities, ENMAX Corporation, Ontario Power Generation and Hydro One), which make coverage ratios much less important than for investor-owned utilities.

Table 10 (b): Fixed Charges Coverage (times) (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	2.40	1.91	1.64	1.65	1.47	1.18	1.21	1.19
EPCOR	1.98	1.84	1.92	1.82	1.81	1.74	1.38	0.80
ENMAX	2.62	3.98	5.15	4.59	2.40	-	-	-
Saskatchewan Power	1.85	1.86	1.79	1.68	1.69	1.37	1.41	1.36
Manitoba Hydro	1.52	1.30	1.19	1.22	1.21	1.15	1.13	1.12
Ontario Hydro	-	-	1.39	1.13	1.23	1.22	1.25	0.91
Ontario Power Generation	7.53	4.96	-	-	-	-	-	-
Hydro One	2.50	2.45	-	-	-	-	-	-
Hydro-Quebec	1.28	1.24	1.18	1.22	1.11	1.06	1.07	1.04
N.B. Power	1.05	1.12	1.13	0.92	0.79	0.74	0.81	0.91
Nfld. & Lab. Hydro	1.17	1.51	1.45	1.24	1.17	1.19	1.11	1.14
Churchill Falls	1.73	1.75	1.68	1.53	1.46	1.50	1.44	1.56
Group Average	*1.72*	*1.59*	*1.33*	*1.24*	*1.21*	*1.14*	*1.16*	*1.01*
Investor Owned								
UtiliCorp Networks Canada (BC)	2.27	2.20	2.22	2.70	2.71	2.47	2.04	1.95
ATCO Electric	2.52	2.47	2.41	2.22	2.03	2.00	1.96	1.85
TransAlta Utilities	2.05	2.10	2.75	2.49	2.99	2.66	2.49	2.32
Northern Ontario Power	2.34	2.81	1.44	2.06	2.20	2.19	1.94	2.61
Nova Scotia Power	1.98	1.93	1.78	1.82	1.62	1.49	1.39	1.32
Group Average	*2.17*	*2.17*	*2.29*	*2.20*	*2.25*	*2.06*	*1.95*	*1.86*
Industry Average	1.75	1.63	1.38	1.29	1.27	1.20	1.21	1.06

(1) Before capitalized interest, AFUDC, debt amortizations and retractable preferred dividends.

For government-owned utilities, the EBIT and fixed charges coverage ratios are the same because they have no preferred shares, except for EPCOR that issued preferred shares in 2001. The high debt levels of the government-owned utilities have resulted in weaker coverage ratios than for investor-owned utilities. Unlike the EBIT interest coverage ratios, the fixed charges coverage ratios for investor-owned utilities remained relatively stable in 2000 as the decline in preferred dividends generally offset the negative impact of the decline in operating income. Coverage ratios should generally improve for government-owned utilities as debt levels are reduced, and should improve for investor-owned utilities as earnings grow and high coupon debt is refinanced at the current lower levels. With the trend towards hybrid securities, super subordinated debt and preferred shares with heavy equity characteristics are being issued.

Table 11: Cash Flow /Total Debt (times) (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	0.13	0.13	0.11	0.11	0.09	0.07	0.06	0.06
EPCOR	0.14	0.15	0.17	0.17	0.15	0.13	0.08	0.02
ENMAX	0.14	0.51	0.59	0.45	0.30	-	-	-
Saskatchewan Power	0.18	0.17	0.17	0.17	0.16	0.11	0.10	0.09
Manitoba Hydro	0.08	0.06	0.06	0.06	0.06	0.05	0.04	0.05
Ontario Hydro	-	-	0.09	0.07	0.07	0.07	0.06	0.03
Ontario Power Generation	0.27	0.28	-	-	-	-	-	-
Hydro One	0.15	0.15	-	-	-	-	-	-
Hydro-Quebec	0.08	0.07	0.06	0.06	0.05	0.04	0.05	0.05
N.B. Power	0.07	0.08	0.08	0.05	0.04	0.04	0.04	0.05
Nfld. & Lab. Hydro	0.06	0.11	0.09	0.06	0.04	0.04	0.05	0.05
Churchill Falls	0.14	0.14	0.12	0.10	0.09	0.09	0.09	0.10
Group Average	*0.11*	*0.10*	*0.08*	*0.07*	*0.07*	*0.06*	*0.06*	*0.05*
Investor Owned								
UtiliCorp Networks Canada (BC)	0.10	0.11	0.11	0.13	0.14	0.17	0.20	0.17
ATCO Electric	0.18	0.20	0.19	0.17	0.16	0.14	0.13	0.13
TransAlta Utilities	0.26	0.21	0.25	0.26	0.28	0.25	0.25	0.23
Northern Ontario Power	0.13	0.13	0.07	0.12	0.12	0.12	0.11	0.13
Nova Scotia Power	0.14	0.13	0.12	0.12	0.11	0.08	0.09	0.09
Group Average	*0.18*	*0.17*	*0.17*	*0.18*	*0.17*	*0.15*	*0.15*	*0.15*
Industry Average	0.12	0.11	0.08	0.08	0.07	0.06	0.06	0.05

(1) Cash flow before working capital, after all preferred dividends. Total debt includes debt equivalents; net of sinking fund assets.

Given the high leverage for most government-owned utilities, cash flow/total debt tends to be weaker than for investor-owned utilities. This ratio continued to improve for government-owned utilities in 2000 largely due to the high cash flow generation. It should continue to improve as debt continues to be paid down and as cash flows continue to grow. Average cash flow/total debt has remained essentially unchanged for investor-owned utilities for the past five years, although the ratio has tended to fluctuate from year to year for those companies with important distribution and transmission businesses as a result of the time lag in recovering deferral accounts.

Table 12: Cash Flow/Capital Expenditures (times) (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	2.45	2.31	2.18	2.86	2.50	1.61	1.33	1.36
EPCOR	1.53	1.03	1.36	2.27	3.17	3.43	1.49	0.18
ENMAX	1.09	1.26	2.93	3.23	1.58	-	-	-
Saskatchewan Power	1.40	1.47	2.28	2.22	3.20	1.40	0.99	0.76
Manitoba Hydro	1.43	1.15	0.98	1.35	1.03	1.00	1.03	0.94
Ontario Hydro	-	-	3.33	2.51	2.67	2.64	2.25	0.60
Ontario Power Generation	1.62	1.51	-	-	-	-	-	-
Hydro One	1.58	1.34	-	-	-	-	-	-
Hydro-Quebec	1.80	1.69	1.12	1.48	0.99	0.63	0.59	0.47
N.B. Power	1.81	2.49	3.80	2.76	1.87	0.75	0.90	0.59
Nfld. & Lab. Hydro	1.33	1.97	3.11	2.30	1.61	1.34	2.38	2.21
Churchill Falls	13.00	21.61	16.53	21.57	15.21	12.69	18.34	17.63
Group Average	*1.87*	*1.71*	*1.80*	*1.96*	*1.61*	*1.19*	*1.03*	*0.59*
Investor Owned								
UtiliCorp Networks Canada (BC)	0.61	0.56	0.60	0.87	0.85	0.79	0.93	0.85
ATCO Electric	2.04	2.15	1.84	1.71	1.63	1.65	1.90	1.66
TransAlta Utilities	1.89	1.45	2.09	1.96	1.92	2.70	2.93	2.14
Northern Ontario Power	1.60	1.97	0.95	1.79	3.58	3.18	3.03	5.35
Nova Scotia Power	2.03	2.07	1.70	2.23	2.28	1.73	1.73	1.31
Group Average	*1.85*	*1.69*	*1.77*	*1.90*	*1.89*	*2.07*	*2.21*	*1.78*
Industry Average	1.87	1.70	1.80	1.95	1.64	1.26	1.10	0.66

(1) Cash flow before working capital, after all preferred dividends. Capital expenditures net of customer contributions.

Given the lack of major capital expansion projects over the past five years, the proportion of capital expenditures funded by operating cash flow has been rising. This trend is expected to continue for most utilities, although a few of the above-mentioned utilities have announced intentions of significant capital expansions over the medium term. Both Great Lakes Power and TransAlta Corporation have announced significant generation expansion programs. Investor-owned utilities tend to be much more ambitious in terms of expansion programs, in part due to their ability to access to the equity markets.

Table 13: Common Dividend Payout Ratio (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	43.3%	62.9%	80.1%	63.4%	32.1%	76.7%	107.0%	128.9%
EPCOR	47.2%	60.5%	45.1%	47.5%	48.6%	31.4%	37.5%	130.8%
ENMAX	67.1%	76.2%	83.8%	106.2%	269.8%	-	-	-
Saskatchewan Power	54.8%	44.1%	55.0%	54.5%	53.5%	69.2%	56.8%	71.2%
Manitoba Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ontario Hydro	-	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ontario Power Generation	33.9%	34.8%	-	-	-	-	-	-
Hydro One	55.9%	37.4%	-	-	-	-	-	-
Hydro-Quebec	50.0%	50.0%	41.3%	46.1%	0.0%	0.0%	0.0%	0.0%
N.B. Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nfld. & Lab. Hydro	200.3%	24.9%	24.1%	48.2%	44.6%	59.3%	0.0%	0.0%
Churchill Falls	57.0%	71.7%	86.3%	99.6%	76.6%	77.3%	67.6%	81.3%
Group Average	44.3%	45.4%	32.3%	44.8%	17.9%	16.8%	14.8%	29.0%
Investor Owned								
UtiliCorp Networks Canada (BC)	52.0%	56.6%	62.6%	54.2%	56.5%	60.6%	63.2%	69.7%
ATCO Electric	99.7%	79.1%	63.2%	56.4%	68.3%	60.0%	79.6%	76.0%
TransAlta Utilities	388.6%	194.7%	110.1%	210.8%	100.0%	123.4%	91.4%	99.9%
Northern Ontario Power	76.9%	115.0%	29.8%	181.3%	128.1%	96.3%	67.3%	115.6%
Nova Scotia Power	89.9%	70.0%	83.2%	75.4%	76.3%	70.4%	68.9%	56.4%
Group Average	167.0%	109.9%	88.2%	129.9%	88.2%	93.9%	81.4%	82.7%
Industry Average	47.1%	34.6%	44.3%	57.6%	36.0%	33.8%	25.8%	43.2%

(1) Based on divdends declared; earnings before extraordinary items.

With the significant improvement in provinces' fiscal results, some provincial governments have generally reduced their dividend payout requirements from the government-owned utilities. However, most provincial governments have instead established dividend payout policies, which provide the utilities with more certainty as to the amount of retained earnings available for expansion.

For investor-owned utilities, the dividend payout policies are generally linked to the maintenance of the target regulated capital structures.

Table 14: Profit Returned to Government (before extraordinary items) (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	59.9%	77.9%	95.2%	82.1%	90.4%	93.7%	102.2%	109.5%
EPCOR	59.6%	71.6%	68.2%	69.7%	67.1%	46.9%	53.9%	114.1%
ENMAX	87.1%	88.5%	66.5%	72.2%	102.9%	-	-	-
Saskatchewan Power	66.1%	59.8%	94.7%	69.1%	53.9%	75.4%	68.3%	96.8%
Manitoba Hydro	37.6%	49.8%	54.6%	52.5%	53.1%	60.7%	62.8%	53.0%
Ontario Hydro	-	-	22.5%	52.2%	33.0%	31.1%	24.9%	96.6%
Ontario Power Generation	72.2%	78.1%	-	-	-	-	-	-
Hydro One	99.8%	37.1%	-	-	-	-	-	-
Hydro-Quebec	65.1%	63.0%	78.4%	73.0%	59.4%	65.2%	50.0%	46.1%
N.B. Power	100.0%	68.0%	66.1%	166.2%	139.4%	361.0%	63.6%	48.4%
Nfld. & Lab. Hydro	176.8%	35.3%	34.8%	58.7%	59.7%	69.1%	33.3%	29.5%
Churchill Falls	63.0%	75.8%	88.4%	99.7%	80.2%	80.6%	72.6%	84.1%
Group Average	68.6%	65.7%	64.1%	71.4%	61.6%	61.1%	52.2%	69.1%

(1) Profit includes dividends, water rentals, property + municipal taxes, debt guarantee fees and for HO + OPG, includes proxy income taxes.

Governments receive returns from their utilities in the form of debt guarantee fees, royalties, water rentals, property and other municipal taxes, capital tax levies and dividends. In addition, Ontario Power Generation and Hydro One now pay proxy provincial income taxes. Given the significant improvement in provinces’ fiscal results over the past five years, provincial governments are no longer as pressured to extract increasing amounts of cash from their electrical utilities. However, with the recent sharp slowdown in economic growth and the negative impact this is having on provinces’ finances, provincial governments may seek to increase the returns from their utilities in the short term to maintain balanced budgets. Dividend payouts for BC Hydro, EPCOR Utilities, Saskatchewan Power and Manitoba Hydro, in particular, fell sharply.

Section C – Unit Revenues and Costs

Note: The following statistics are not strictly comparable from one utility to the next, given the changing strategic focuses of many of the utilities. For example, EPCOR Utilities is involved not only in electricity generation, transmission and distribution, but also water distribution. It is also increasingly expanding into retail marketing. Ontario Power Generation and TransAlta Utilities are involved only in generation (TransAlta Utilities has not yet closed its transmission sale, but the 2000 numbers reported include only generation).

Table 15 (a): Operation & Maintenance Costs - Self-Generation - cents/net generated kWh sold

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	1.62	0.99	0.87	0.80	0.85	0.96	0.99	1.04
EPCOR	2.78	2.13	1.80	1.93	1.83	1.28	1.06	1.89
Saskatchewan Power	1.90	1.73	1.57	1.44	1.35	1.65	1.68	1.68
Manitoba Hydro	1.03	1.05	0.86	0.72	0.81	0.88	0.91	0.90
Ontario Hydro	-	-	1.78	1.73	1.56	1.45	1.42	1.69
Ontario Power Generation	1.61	1.78	-	-	-	-	-	-
Hydro-Quebec	1.51	1.39	1.33	1.17	1.08	1.16	1.30	1.42
N.B. Power	1.57	1.78	1.34	1.44	1.74	2.05	1.84	1.83
Nfld. & Lab. Hydro	1.62	1.54	1.54	1.28	1.37	1.37	1.44	1.38
Churchill Falls	0.10	0.08	0.07	0.08	0.09	0.09	0.09	0.07
Group Average	*1.48*	*1.40*	*1.31*	*1.23*	*1.18*	*1.19*	*1.22*	*1.36*
Investor Owned								
UtiliCorp Networks Canada (BC)	1.96	1.91	1.84	1.81	2.01	1.85	1.87	1.92
ATCO Electric	1.80	1.72	1.55	1.59	1.74	1.77	1.63	1.52
TransAlta Utilities	0.56	1.02	1.01	1.15	0.97	0.90	0.99	0.91
Northern Ontario Power	1.46	1.28	1.40	1.45	1.41	1.26	1.55	1.18
Nova Scotia Power	1.51	1.44	1.47	1.51	1.77	1.72	1.73	1.73
Group Average	*1.03*	*1.26*	*1.23*	*1.32*	*1.30*	*1.23*	*1.28*	*1.21*
Industry Average	1.62	1.57	1.31	1.25	1.20	1.21	1.25	1.36

Operating and maintenance costs tend to be highest for nuclear- and coal-based generation, and lowest for hydro-based generation. Most utilities have average O&M costs in the 1¢-2¢ per kWh range, and this level will likely be maintained. The smaller utilities tend to have higher unit O&M costs largely due to their small distribution bases and, consequently, the lack of economies of scale. Note the low O&M costs of Churchill Falls. O&M costs are slowing edging upwards, especially with some of the aging coal-based generators.

Table 15 (b): Fuel Costs - Self-Generation - cents/net generated kWh sold

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	0.98	0.17	0.16	0.04	0.03	0.16	0.20	0.15
EPCOR	3.19	1.68	1.40	1.18	0.98	1.29	1.53	1.61
Saskatchewan Power	2.11	1.22	1.12	1.03	0.93	0.93	0.93	0.86
Manitoba Hydro	0.11	0.06	0.08	0.03	0.03	0.03	0.03	0.03
Ontario Hydro	-	-	0.29	0.55	0.48	0.45	0.43	0.72
Ontario Power Generation	0.93	0.75	-	-	-	-	-	-
Hydro-Quebec	0.51	0.43	0.35	0.18	0.02	0.01	0.02	0.02
N.B. Power	2.36	1.45	1.51	1.81	1.62	1.78	1.14	1.09
Nfld. & Lab. Hydro	0.74	0.63	0.51	0.74	0.72	0.71	0.70	0.74
Churchill Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Group Average	*0.82*	*0.54*	*0.37*	*0.37*	*0.28*	*0.29*	*0.28*	*0.36*
Investor Owned								
UtiliCorp Networks Canada (BC)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATCO Electric	1.20	1.16	0.88	0.85	0.87	0.96	0.95	0.94
TransAlta Utilities	0.43	0.41	0.41	0.39	0.39	0.38	0.38	0.37
Northern Ontario Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nova Scotia Power	2.43	2.43	2.52	2.44	2.49	2.67	2.73	2.76
Group Average	*0.96*	*0.93*	*0.90*	*0.84*	*0.84*	*0.88*	*0.90*	*0.89*
Industry Average	0.83	0.58	0.43	0.42	0.33	0.35	0.35	0.42

Fuel costs are very low for the predominantly hydro-based generating companies (and non-existent for those utilities that are 100% hydro-based). Utilities that are predominantly coal-based or nuclear-based also tend to have low fuel costs due to the low cost of coal. However, utilities that have gas-based or oil-based generation (i.e., EPCOR Utilities and N.B. Power) saw their fuel costs rise sharply in 2000 with the spike up in oil and gas prices. The cost structure for these two types of generation tends to be the most volatile due to volatile nature of oil and gas prices. 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.

Table 15 (c): Income Taxes - Self-Generation - cents/net generated kWh sold

Investor Owned	2000	1999	1998	1997	1996	1995	1994	1993
Ontario Power Generation	0.33	0.29	-	-	-	-	-	-
Hydro One	0.13	0.12	-	-	-	-	-	-
UtiliCorp Networks Canada (BC)	0.50	0.40	0.45	0.66	0.76	0.53	0.24	0.39
ATCO Electric	0.92	0.97	1.00	0.93	1.03	1.01	0.95	0.94
TransAlta Utilities	0.26	0.38	0.60	0.51	0.73	0.68	0.69	0.69
Northern Ontario Power	0.69	0.99	0.48	0.78	0.72	0.71	0.55	0.78
Nova Scotia Power	0.14	0.13	0.14	0.15	0.13	0.06	0.01	0.06
Group Average (1)	*0.37*	*0.45*	*0.57*	*0.53*	*0.67*	*0.62*	*0.59*	*0.61*

(1) Excludes OPG and Hydro One.

On average, investor-owned utilities pay income taxes of around 0.40¢ per kWh range, while government-owned utilities do not pay income taxes, with the exception of Ontario Power Generation and Hydro One who pay proxy provincial income taxes to service about $21 billion of Ontario Hydro's stranded debt and to create a level playing field with investor-owned utilities. EPCOR Utilities also began paying payments-in-lieu of taxes effective January 1, 2001, in order to create a level playing field with investor-owned utilities in Alberta.

Table 16 (a): Fixed Costs - Self-Generation - cents/net generated kWh sold

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	2.94	2.91	2.98	2.88	2.88	3.53	3.52	3.44
EPCOR	2.75	2.81	2.68	3.32	3.28	2.53	2.14	2.95
Saskatchewan Power	2.50	2.39	2.48	2.69	2.78	2.82	2.81	2.74
Manitoba Hydro	2.81	2.93	2.69	2.41	2.50	2.70	2.73	2.64
Ontario Hydro	-	-	3.81	3.91	3.97	4.03	3.88	4.01
Ontario Power Generation	0.94	1.10	-	-	-	-	-	-
Hydro-Quebec	4.16	4.20	4.49	4.01	3.83	3.70	3.43	3.35
N.B. Power	3.19	3.55	3.10	3.52	4.19	4.54	3.97	3.03
Nfld. & Lab. Hydro	2.25	2.33	2.46	2.32	2.46	2.45	2.58	2.53
Churchill Falls	0.10	0.11	0.10	0.12	0.13	0.13	0.13	0.13
Group Average	*2.46*	*2.54*	*3.40*	*3.33*	*3.38*	*3.42*	*3.26*	*3.21*
Investor Owned								
UtiliCorp Networks Canada (BC)	3.38	3.34	3.34	3.15	3.42	3.13	2.80	2.57
ATCO Electric	2.51	2.55	2.36	2.32	2.49	2.52	2.38	2.40
TransAlta Utilities	1.07	1.42	1.43	1.41	1.50	1.49	1.51	1.50
Northern Ontario Power	2.51	2.20	3.51	2.56	2.18	2.18	2.32	1.82
Nova Scotia Power	2.51	2.60	2.60	2.69	2.58	2.47	2.35	2.19
Group Average	*1.72*	*1.94*	*1.93*	*1.90*	*1.95*	*1.91*	*1.88*	*1.83*
Industry Average	2.56	2.67	3.27	3.21	3.26	3.29	3.14	3.09

Fixed costs, which consist primarily of depreciation, government levies, and interest costs, have typically remained in the range of 2.5¢-3.5¢ per kWh for the past ten years. The higher levels of debt carried by most government-owned utilities have resulted in higher interest costs and, thus, higher fixed costs. However, there was little change in unit fixed costs in 2000 relative to 1999 for government-owned utilities, with the average remaining close to 2.5¢ per kW. Investor-owned utilities tend to have lower leverage resulting in lower relative interest costs. Unit depreciation costs have generally been similar for government-owned utilities and investor-owned utilities. Government levies account for an important share of fixed costs for UtiliCorp Networks Canada (BC), BC Hydro and Northern Ontario Power.

Table 16 (b): Net Interest Expense (1) - Self-Generation - cents/net generated kWh sold

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	1.12	1.14	1.25	1.19	1.25	1.77	1.79	1.78
EPCOR	1.37	1.40	1.30	1.68	1.75	1.71	1.73	2.48
Saskatchewan Power	0.94	1.01	1.06	1.14	1.29	1.36	1.37	1.33
Manitoba Hydro	1.38	1.50	1.50	1.35	1.44	1.61	1.66	1.71
Ontario Hydro	-	-	2.25	2.35	2.38	2.49	2.51	2.88
Ontario Power Generation	0.12	0.15	-	-	-	-	-	-
Hydro-Quebec	2.39	2.42	2.62	2.33	2.36	2.45	2.42	2.52
N.B. Power	1.59	1.90	1.64	1.96	2.32	2.77	2.44	2.32
Nfld. & Lab. Hydro	1.48	1.48	1.60	1.58	1.71	1.73	1.87	1.83
Churchill Falls	0.04	0.04	0.04	0.06	0.06	0.06	0.07	0.06
Group Average	*1.16*	*1.20*	*1.89*	*1.87*	*1.96*	*2.11*	*2.11*	*2.25*
Investor Owned								
UtiliCorp Networks Canada (BC)	1.13	1.05	0.99	0.89	0.97	0.84	0.78	0.63
ATCO Electric	1.03	1.03	0.95	0.98	1.10	1.12	1.06	1.10
TransAlta Utilities	0.38	0.43	0.45	0.49	0.50	0.51	0.53	0.52
Northern Ontario Power	0.68	0.60	1.13	1.00	1.07	1.05	1.18	0.91
Nova Scotia Power	1.06	1.11	1.16	1.28	1.42	1.48	1.61	1.81
Group Average	*0.66*	*0.70*	*0.72*	*0.75*	*0.81*	*0.82*	*0.85*	*0.88*
Industry Average	1.21	1.26	1.79	1.78	1.86	2.00	2.00	2.12

(1) Excludes capitalized interest and retractable preferred dividends.

Interest costs typically amount to 1.5¢-2.5¢ per kWh for government-owned utilities, while investor-owned utilities are generally below 1.0¢ per kWh. The higher volumes of electricity produced in 2000 were largely responsible for reducing unit interest costs, although the slight decline in interest costs also helped. The higher leveraged utilities such as Hydro-Québec and N.B. Power have the highest unit interest costs. Ontario Power Generation and Churchill Falls, on the other hand, have the lowest leverage of the government-owned utilities and, thus, have the lowest unit interest costs. The continued refinancing of high coupon debt at the current low interest rates will continue to push these unit costs down. The continuation of debt paydown for the government-owned utilities will also help to reduce these costs.

Table 16 (c): Preferred Dividends - Self-Generation - cents/net generated kWh sold

Investor Owned	2000	1999	1998	1997	1996	1995	1994	1993
UtiliCorp Networks Canada (BC)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13
ATCO Electric	0.10	0.13	0.18	0.20	0.26	0.29	0.31	0.38
TransAlta Utilities	0.05	0.08	0.08	0.08	0.09	0.12	0.14	0.19
Northern Ontario Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nova Scotia Power	0.10	0.11	0.12	0.10	0.15	0.20	0.19	0.04
Group Average	*0.06*	*0.09*	*0.10*	*0.10*	*0.13*	*0.15*	*0.17*	*0.19*

Preferred dividends are no longer a significant fixed cost for investor-owned utilities, and on average amount to less than 0.10¢ per kWh. Only a select few utilities continue to have preferred shares.

Table 16 (d): Government Levies - Self-Generation - cents/net generated kWh sold (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	0.92	0.93	0.94	0.95	0.95	0.99	1.00	0.98
EPCOR	0.47	0.52	0.50	0.58	0.62	0.48	0.48	0.68
Saskatchewan Power	0.32	0.31	0.32	0.33	0.34	0.34	0.37	0.33
Manitoba Hydro	0.58	0.59	0.46	0.42	0.42	0.43	0.39	0.33
Ontario Hydro	-	-	0.22	0.22	0.22	0.21	0.21	0.22
Ontario Power Generation	0.28	0.38	-	-	-	-	-	-
Hydro-Quebec	0.52	0.60	0.66	0.59	0.56	0.53	0.51	0.54
N.B. Power	0.29	0.33	0.29	0.34	0.40	0.45	0.38	0.36
Nfld. & Lab. Hydro	0.19	0.20	0.21	0.19	0.19	0.18	0.19	0.18
Churchill Falls	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Group Average	*0.45*	*0.50*	*0.46*	*0.45*	*0.44*	*0.41*	*0.40*	*0.40*
Investor Owned								
UtiliCorp Networks Canada (BC)	1.56	1.58	1.58	1.44	1.65	1.59	1.47	1.46
ATCO Electric	0.29	0.32	0.30	0.29	0.30	0.32	0.30	0.30
TransAlta Utilities	0.11	0.13	0.16	0.16	0.16	0.17	0.17	0.18
Northern Ontario Power	0.78	0.66	0.94	0.62	0.53	0.66	0.66	0.53
Nova Scotia Power	0.17	0.16	0.13	0.11	0.06	0.06	0.06	0.06
Group Average	*0.21*	*0.22*	*0.23*	*0.22*	*0.22*	*0.23*	*0.23*	*0.23*
Industry Average	0.43	0.49	0.44	0.42	0.42	0.39	0.38	0.38

(1) Government levies include dividends, water rentals, property + municipal taxes, debt guarantee fees and for OPG, includes proxy income taxes.

Government levies include debt guarantee fees, water taxes, property and other municipal taxes, and dividend payments (for government-owned utilities). For government-owned utilities, the range is quite wide from as little as 0.01¢ per kWh for Churchill Falls to almost 1.0¢ per kWh for BC Hydro. The range is also quite wide for investor-owned utilities, with UtiliCorp Networks Canada (BC) facing the highest unit government levies and TransAlta Utilities facing the lowest. Clearly, utilities operating in B.C. face the highest government levies in Canada.

Unit government levies came down in 2000 relative to 1999, largely due to the sharp decline in Ontario Power Generation's government levies, but are expected to remain relatively stable. No additional new levies or taxes are expected to be imposed.

Table 16 (e): Depreciation - Self-Generation - cents/net generated kWh sold (1)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	0.82	0.78	0.72	0.70	0.66	0.74	0.71	0.75
EPCOR	1.06	0.99	0.91	1.10	0.91	0.72	0.61	0.85
Saskatchewan Power	1.19	1.02	1.03	1.16	1.11	1.09	1.03	1.05
Manitoba Hydro	0.89	0.88	0.76	0.65	0.65	0.67	0.67	0.65
Ontario Hydro	-	-	1.24	1.25	1.28	1.24	1.17	1.18
Ontario Power Generation	0.56	0.58	-	-	-	-	-	-
Hydro-Quebec	1.38	1.30	1.30	1.17	1.03	0.87	0.83	0.82
N.B. Power	1.21	1.22	1.03	1.13	1.38	1.22	1.22	0.98
Nfld. & Lab. Hydro	0.62	0.65	0.60	0.51	0.50	0.48	0.47	0.42
Churchill Falls	0.05	0.05	0.04	0.05	0.06	0.06	0.05	0.05
Group Average	*0.89*	*0.86*	*1.03*	*1.00*	*0.98*	*0.91*	*0.88*	*0.87*
Investor Owned								
UtiliCorp Networks Canada (BC)	0.74	0.74	0.80	0.84	0.84	0.72	0.58	0.52
ATCO Electric	1.21	1.22	1.15	1.11	1.15	1.14	1.04	1.03
TransAlta Utilities	0.59	0.88	0.83	0.78	0.85	0.82	0.83	0.83
Northern Ontario Power	1.05	0.96	1.47	0.95	0.59	0.49	0.48	0.38
Nova Scotia Power	1.12	1.18	1.13	1.09	0.90	0.75	0.66	0.81
Group Average	*0.82*	*1.00*	*0.96*	*0.91*	*0.90*	*0.85*	*0.82*	*0.84*
Industry Average	0.96	0.95	1.03	1.00	0.98	0.91	0.87	0.87

(1) Depreciation includes other non-cash expenses such site restoration and decommissioning costs.

Unit depreciation costs have averaged about 1.0¢ per kWh for the past five years. The depreciation rates for thermal generation tend to be slightly higher than for hydro generation, but many of the 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, EPCOR, TransAlta Corporation and Great Lakes Power). Hydro-Québec, with its new hydro plants, has the highest rates.

Table 17: Purchased Power - cents/gross kWh purchased

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	16.31	4.19	3.83	3.32	3.41	3.29	2.82	2.96
EPCOR	-	-	-	-	-	-	-	4.18
ENMAX	6.63	4.60	4.41	4.35	4.87	-	-	-
Saskatchewan Power	1.87	2.79	2.92	2.15	1.62	1.72	2.02	1.73
Manitoba Hydro	1.99	1.69	1.97	3.21	3.43	1.72	1.50	1.53
Ontario Hydro	-	-	4.97	6.10	6.17	5.90	5.74	5.22
Ontario Power Generation	4.74	3.41	-	-	-	-	-	-
Hydro One	4.92	5.19	-	-	-	-	-	-
Hydro-Quebec (2)	2.98	1.27	1.07	0.89	0.86	0.87	0.85	0.79
N.B. Power	4.78	3.61	3.82	3.83	3.00	2.38	2.42	2.66
Nfld. & Lab. Hydro	0.80	0.74	0.56	0.61	0.60	0.60	0.62	0.59
Churchill Falls	-	-	-	-	-	-	-	-
Group Average (3)	*8.50*	*4.30*	*3.19*	*3.50*	*3.55*	*2.18*	*1.89*	*1.63*
Investor Owned								
UtiliCorp Networks Canada (BC)	3.10	2.92	2.83	2.57	2.20	2.34	2.40	2.46
ATCO Electric (1)	5.65	1.09	1.26	1.52	1.12	2.19	0.13	2.17
TransAlta Utilities (1)	0.00	0.00	0.00	0.00	0.00	1.19	0.12	-
Northern Ontario Power	4.88	4.83	4.93	4.99	5.59	4.81	4.47	6.13
Nova Scotia Power	7.18	6.08	6.74	6.32	6.75	3.26	3.24	3.01
Group Average	*4.14*	*2.68*	*2.98*	*2.82*	*2.33*	*2.73*	*2.85*	*2.46*
Industry Average (4)	8.30	4.21	3.18	3.45	3.45	2.22	1.94	1.66
(1) Costs distorted by cost averaging mechanism of Alberta Power Pool.								
(2) Includes Churchill Falls purchases	0.28	0.27	0.25	0.27	0.29	0.30	0.28	0.28
(3) Excluding CF >>>	12.45	6.81	5.02	6.52	6.99	4.19	3.88	3.82
(4) Excluding CF >>>	11.89	6.45	4.85	6.09	6.29	3.98	3.77	3.70

The cost of purchased power increased sharply in 2000 due to the spike in electricity prices across the parts of North America that experienced tight demand/supply conditions. The higher electricity prices had a significant impact on BC Hydro and ATCO Electric, although in the case of BC Hydro, the purchased power was largely for trading purposes and was sold at even higher rates. Power purchases are generally used for two reasons: (1) to meet demand requirements; and (2) for trading purposes. In general, when power purchases are used to meet demand requirements, the cost of the power purchased is above that of internally generated power if bought on the spot market. However, power purchases under long-term contracts may be priced close to the cost of internally generated power depending on the demand/supply conditions in existence at the time when the contract was entered into.

In terms of power purchases for trading purposes, the purchased power may be more expensive or less expensive that internally generated power, again depending on market conditions. In the case of hydro-based generators, the strategy is typically to purchase power at “off peak” times at relatively low rates, thus conserving water to be used to generate electricity at “on peak” times, at much higher average prices. This type of strategy has been made possible by the restructuring of the North American electricity industry, making north/south flows in Canada possible. There should be a growing proportion of this type of purchased power in the future, particularly given the establishment of RTOs in the U.S.

Table 18: Electricity Revenues (1) - cents/kWh sold

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	10.87	4.91	4.65	4.42	4.36	4.77	4.81	4.83
EPCOR	11.11	9.19	8.33	9.62	9.27	6.85	6.16	6.66
ENMAX	9.18	6.68	6.59	6.48	6.53	-	-	-
Saskatchewan Power	6.33	5.90	5.81	5.78	5.78	5.82	5.94	5.73
Manitoba Hydro	4.39	4.17	3.88	3.52	3.69	3.85	3.88	3.81
Ontario Hydro	-	-	6.24	6.16	6.23	6.16	6.16	6.30
Ontario Power Generation	4.19	4.08	-	-	-	-	-	-
Hydro One	1.80	1.87	-	-	-	-	-	-
Hydro-Quebec	5.35	4.95	4.96	4.88	4.68	4.56	4.59	4.60
N.B. Power	6.69	6.14	5.71	5.99	5.99	5.70	5.59	5.75
Nfld. & Lab. Hydro	3.68	3.96	3.98	4.30	4.35	4.38	4.39	4.42
Churchill Falls	0.28	0.27	0.25	0.26	0.28	0.29	0.27	0.27
Group Average	*5.91*	*4.75*	*5.08*	*5.04*	*5.03*	*4.88*	*4.89*	*4.88*
Investor Owned								
UtiliCorp Networks Canada (BC)	4.96	4.72	4.71	4.67	4.53	4.46	4.11	4.10
ATCO Electric	7.35	6.67	6.33	6.28	6.42	7.20	7.25	7.32
TransAlta Utilities	2.59	4.10	4.03	3.76	4.13	3.92	4.08	4.28
Northern Ontario Power	5.36	5.36	5.34	5.38	5.41	5.39	5.27	5.31
Nova Scotia Power	7.63	7.62	7.68	7.79	7.99	7.88	7.90	7.87
Group Average	*4.69*	*5.35*	*5.24*	*5.07*	*5.31*	*5.27*	*5.35*	*5.49*
Industry Average	6.14	5.22	5.10	5.05	5.07	4.90	4.92	4.93

(1) Excluding ancillary revenues. For Alberta-based utilities, revenues are net of AEEMA, ASPRDA costs (TransAlta) or recoveries (EPCOR and Cdn Utils)

NOTE: OH rates do not represent electricity rates in Ontario as a material portion of distribution costs (MEUs) are not included.

Unit electricity revenues increased significantly in 2000 largely due to the rise in electricity exports by government-owned utilities and the higher electricity prices in those markets. Average domestic unit electricity revenues, however, remained stable in 2000 at 5.0¢ per kWh for government-owned utilities, but fell to 4.7¢ per kWh for investor-owned utilities due entirely to TransAlta (see note below). Average domestic unit electricity revenues are expected to remain relatively stable in the near term due to (a) the domestic rate freezes in effect until the end of 2002 in some provinces, (b) the decline in the price of natural gas and oil from its peaks in late 2000/early 2001, and (c) the slowdown in the economy which will reduce electricity demand. However, retail prices will rise in Ontario due to the market opening in 2002 and the associated higher distribution costs.

Note: The decline in TransAlta Utilities' unit electricity revenues is due to the sale of its distribution business and the treatment of its transmission business as discontinued, given the announced sale of this operation. Therefore, electricity revenues now only reflect revenues associated with sale of wholesale power and, therefore, are not comparable to the other electric utilities.

Table 19 (a) Pre-Tax Cash Margin (1) **- cents/kWh sold**

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	1.77	1.36	1.20	1.40	1.27	1.00	1.02	1.03
EPCOR	2.39	2.16	2.11	2.48	2.33	1.98	1.27	0.33
ENMAX	0.87	1.00	1.33	1.09	0.64	-	-	-
Saskatchewan Power	1.75	1.84	1.88	1.99	2.04	1.64	1.63	1.60
Manitoba Hydro	1.76	1.39	1.04	1.01	1.00	0.93	0.90	0.87
Ontario Hydro	-	-	1.86	1.39	1.70	1.70	1.72	0.88
Ontario Power Generation	1.29	1.15	-	-	-	-	-	-
Hydro-Quebec	1.48	1.46	1.34	1.37	1.09	0.86	0.85	0.75
N.B. Power	1.17	1.15	1.13	0.80	0.67	0.27	0.57	0.65
Nfld. & Lab. Hydro	0.63	1.06	1.13	0.94	0.80	0.82	0.65	0.68
Churchill Falls	0.13	0.14	0.12	0.12	0.13	0.13	0.11	0.13
Group Average	*1.46*	*1.34*	*1.40*	*1.30*	*1.27*	*1.11*	*1.12*	*0.80*
Investor Owned								
UtiliCorp Networks Canada (BC)	1.07	1.02	1.04	1.25	1.15	1.05	0.75	0.80
ATCO Electric	2.84	2.87	2.92	2.79	2.80	3.14	3.24	3.39
TransAlta Utilities	1.13	1.62	1.98	1.82	2.31	2.18	2.24	2.40
Northern Ontario Power	1.57	1.88	0.90	1.48	1.71	1.70	1.45	1.95
Nova Scotia Power	2.44	2.52	2.41	2.48	2.33	2.17	1.92	1.68
Group Average	*1.72*	*2.01*	*2.14*	*2.07*	*2.32*	*2.26*	*2.23*	*2.32*
Industry Average	1.44	1.36	1.47	1.37	1.38	1.22	1.23	0.95

(1) Cash costs include OM&A, fuel, interest expense, power purchases, levies.

Pre-tax margins improved in 2000 for the government-owned utilities largely due to the strong export revenues, but on average, they remain below those of investor-owned utilities. However, excluding Newfoundland & Labrador Hydro and Churchill Falls, pre-tax margins for government-owned utilities are not significantly dissimilar from those of their investor-owned counterparts. Margins for all utilities should improve as existing high coupon debt continues to be refinanced at lower interest rates and as earnings continue to grow.

Table 19 (b): Net Margins - cents/kWh sold (before extraordinary items/transfers, after preferreds)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	1.19	0.78	0.63	0.78	0.66	0.32	0.39	0.43
EPCOR	1.48	1.25	1.23	1.42	1.42	1.65	1.35	0.53
ENMAX	0.59	0.62	0.93	0.76	0.32	0.00	0.00	0.00
Saskatchewan Power	0.74	0.88	0.86	0.85	0.94	0.54	0.60	0.55
Manitoba Hydro	0.94	0.57	0.36	0.38	0.37	0.28	0.23	0.29
Ontario Hydro	-	-	0.68	0.18	0.42	0.45	0.60	0.01
Ontario Power Generation	0.43	0.33	-	-	-	-	-	-
Hydro-Quebec	0.58	0.54	0.43	0.48	0.32	0.23	0.42	0.50
N.B. Power	(0.00)	0.12	0.09	(0.23)	(0.49)	(0.63)	(0.36)	0.33
Nfld. & Lab. Hydro	0.21	0.61	0.67	0.46	0.31	0.35	0.20	0.21
Churchill Falls	0.08	0.09	0.08	0.07	0.07	0.07	0.07	0.08
Group Average	*0.73*	*0.60*	*0.53*	*0.40*	*0.39*	*0.30*	*0.43*	*0.29*
Investor Owned								
UtiliCorp Networks Canada (BC)	0.48	0.45	0.42	0.48	0.44	0.41	0.34	0.30
ATCO Electric	0.94	0.91	0.90	0.83	0.76	0.92	0.93	0.97
TransAlta Utilities	0.27	0.32	0.52	0.50	0.68	0.62	0.62	0.65
Northern Ontario Power	0.56	0.69	0.14	0.43	0.72	0.95	0.79	1.02
Nova Scotia Power	0.97	1.00	0.87	0.97	0.98	1.05	1.05	1.27
Group Average	*0.55*	*0.58*	*0.63*	*0.64*	*0.74*	*0.75*	*0.74*	*0.82*
Industry Average	0.74	0.62	0.46	0.34	0.32	0.22	0.31	0.18

Net margins improved significantly in 2000 for government-owned utilities due to the sharp increase in export revenues. Given the strong export revenues and the fact that government-owned utilities do not pay corporate taxes (with the exception of Ontario Power Generation and Hydro One), average net margins for government-owned utilities jumped sharply above those of investor-owned utilities. This is unlikely to remain the case in 2001 given the decline in electricity prices observed in the key export markets.

Section D – Operating Efficiencies & Profitability

Table 20: Operating Margins

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	18.0%	32.3%	33.9%	40.5%	40.9%	39.5%	39.7%	39.8%
EPCOR	19.0%	23.5%	25.2%	27.0%	28.8%	42.8%	38.2%	26.9%
ENMAX	18.5%	25.2%	35.0%	35.5%	20.1%	-	-	-
Saskatchewan Power	24.0%	30.5%	32.4%	33.7%	37.8%	32.5%	33.2%	32.6%
Manitoba Hydro	46.2%	43.7%	44.5%	48.2%	48.4%	47.9%	48.6%	49.8%
Ontario Hydro	-	-	42.5%	37.5%	42.2%	45.1%	47.3%	39.4%
Ontario Power Generation	20.0%	17.4%	-	-	-	-	-	-
Hydro One	43.7%	45.6%	-	-	-	-	-	-
Hydro-Quebec	37.4%	42.3%	43.6%	46.2%	47.9%	48.5%	47.7%	46.6%
N.B. Power	21.9%	26.8%	28.5%	24.5%	22.8%	22.2%	26.9%	30.8%
Nfld. & Lab. Hydro	33.3%	41.2%	45.6%	43.3%	42.5%	43.6%	42.5%	43.6%
Churchill Falls	42.1%	47.3%	48.0%	45.6%	43.8%	45.3%	48.3%	50.7%
Group Average	*27.3%*	*32.2%*	*39.8%*	*39.7%*	*42.0%*	*44.2%*	*45.1%*	*41.5%*
Investor Owned								
UtiliCorp Networks Canada (BC)	24.7%	23.8%	23.6%	26.6%	26.3%	24.4%	20.3%	20.5%
ATCO Electric	36.5%	40.7%	43.4%	42.5%	43.0%	43.3%	45.0%	47.4%
TransAlta Utilities	36.0%	33.1%	40.5%	38.8%	45.6%	45.6%	45.2%	47.2%
Northern Ontario Power	25.3%	30.9%	14.4%	28.2%	38.3%	38.2%	35.9%	44.8%
Nova Scotia Power	31.1%	31.8%	31.6%	33.7%	35.0%	35.9%	35.6%	33.3%
Group Average	*33.4%*	*34.0%*	*36.7%*	*37.2%*	*41.0%*	*41.3%*	*41.2%*	*42.3%*
Industry Average	27.8%	32.4%	39.5%	39.4%	41.9%	43.9%	44.6%	41.6%

Operating margins are defined as operating income divided by total revenues. Predominantly hydro-based utilities have operating margins around 40% and higher. Investor-owned utilities, which tend to be non-hydro-based, generally have lower operating margins because of higher fuel costs.

Table 21: Net Margins/Rate Reductions before Utilities is Breakeven (net margin before extraordinary items, after preferreds)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	10.9%	15.7%	13.5%	17.4%	14.9%	6.6%	8.1%	8.7%
EPCOR	10.5%	11.7%	12.4%	12.5%	12.9%	23.7%	21.5%	7.7%
ENMAX	17.7%	22.4%	32.0%	30.5%	14.9%	0.0%	0.0%	0.0%
Saskatchewan Power	11.4%	14.6%	14.7%	14.4%	16.1%	9.2%	10.1%	9.6%
Manitoba Hydro	19.4%	12.6%	9.3%	10.6%	9.9%	7.1%	5.9%	7.6%
Ontario Hydro	-	-	10.5%	2.8%	6.4%	7.0%	9.5%	0.1%
Ontario Power Generation	10.1%	7.7%	-	-	-	-	-	-
Hydro One	17.9%	19.3%	-	-	-	-	-	-
Hydro-Quebec	9.4%	9.4%	7.7%	9.3%	6.8%	5.1%	9.2%	10.8%
N.B. Power	0.0%	1.9%	1.5%	-3.8%	-8.0%	-10.7%	-6.2%	5.6%
Nfld. & Lab. Hydro	11.5%	21.5%	28.9%	19.1%	13.1%	15.1%	10.8%	12.6%
Churchill Falls	28.2%	31.4%	31.1%	25.0%	23.7%	25.4%	24.3%	28.2%
Group Average	*10.3%*	*10.6%*	*9.9%*	*7.8%*	*7.9%*	*6.5%*	*9.1%*	*5.9%*
Investor Owned								
UtiliCorp Networks Canada (BC)	9.4%	9.2%	8.6%	10.0%	9.5%	9.0%	8.0%	7.1%
ATCO Electric	12.7%	13.6%	14.2%	13.2%	11.9%	12.7%	12.8%	13.3%
TransAlta Utilities	10.3%	8.9%	13.0%	12.5%	15.7%	15.0%	14.5%	14.9%
Northern Ontario Power	10.5%	12.8%	2.6%	8.0%	13.4%	17.7%	15.0%	19.1%
Nova Scotia Power	12.7%	12.9%	11.3%	12.4%	12.1%	13.2%	13.1%	16.0%
Group Average	*11.7%*	*11.4%*	*12.1%*	*12.3%*	*13.6%*	*13.8%*	*13.5%*	*14.7%*
Industry Average	12.3%	12.7%	10.3%	8.3%	8.4%	7.2%	9.6%	7.2%

Net margins for Canadian utilities have generally been around 10%, which does not provide a significant amount of flexibility. Net margins have improved over time for the government-owned utilities, while they have generally deteriorated for the investor-owned utilities. However, given that most of the utilities remain regulated (or a significant portion of their operations remain regulated), the thin margins are less of concern relative to non-regulated companies.

Table 22: Return on Average Common Equity (before extraordinary items)

Government Owned	2000	1999	1998	1997	1996	1995	1994	1993
B.C. Hydro	60.4%	40.4%	31.9%	36.0%	30.6%	13.4%	16.5%	16.2%
EPCOR	17.0%	14.2%	15.6%	16.1%	19.0%	24.3%	22.8%	7.0%
ENMAX	13.4%	13.9%	22.0%	18.1%	14.4%	0.0%	0.0%	0.0%
Saskatchewan Power	10.3%	12.3%	12.6%	12.6%	14.4%	8.3%	9.1%	8.6%
Manitoba Hydro	28.3%	20.5%	16.3%	21.6%	25.0%	22.0%	21.8%	35.9%
Ontario Hydro	-	-	-24.5%	-25.6%	16.1%	14.9%	23.6%	0.2%
Ontario Power Generation	10.8%	8.2%	-	-	-	-	-	-
Hydro One	9.9%	13.1%	-	-	-	-	-	-
Hydro-Quebec	7.6%	6.6%	5.1%	6.1%	4.3%	3.3%	5.9%	7.2%
N.B. Power	0.0%	218.2%	8.4%	-9.9%	-18.2%	-23.6%	-13.1%	12.0%
Nfld. & Lab. Hydro	5.8%	11.2%	12.3%	8.2%	5.7%	6.7%	4.5%	5.4%
Churchill Falls	7.8%	8.6%	8.8%	6.6%	5.9%	6.7%	6.4%	8.0%
Group Average	*23.1%*	*12.5%*	*17.7%*	*11.4%*	*9.2%*	*7.2%*	*10.7%*	*6.3%*
Investor Owned								
UtiliCorp Networks Canada (BC)	10.4%	10.5%	10.3%	12.5%	12.7%	11.9%	10.1%	9.6%
ATCO Electric	12.3%	11.7%	12.2%	11.7%	10.8%	12.5%	12.9%	13.2%
TransAlta Utilities	7.5%	7.3%	11.7%	11.1%	14.1%	12.9%	12.4%	12.3%
Northern Ontario Power	2.8%	3.5%	0.7%	2.1%	5.4%	14.4%	11.8%	15.2%
Nova Scotia Power	10.9%	11.1%	9.5%	10.6%	10.6%	11.5%	11.9%	14.9%
Group Average	*9.0%*	*8.9%*	*9.7%*	*9.9%*	*11.6%*	*12.5%*	*12.3%*	*13.2%*
Industry Average	13.9%	14.7%	16.1%	11.0%	9.2%	7.6%	10.5%	7.2%

The small equity bases of government-owned utilities distort this ratio and can make it appear much higher than for investor-owned utilities. Investor-owned utilities have typically generated returns around 10%, which is respectable and more representative of industry performance than the returns of government-owned utilities. Unlike the government-owned utilities, investor-owned utilities are subject to earnings restrictions in the form of approved ROEs although they usually earn more than their approved ROE.

Section E – Canadian – U.S. Comparisons

Table 23: % Debt in the Capital Structure (1)

Canadian Government Owned	2000	1999	1998	1997	1996	1995
British Columbia Hydro	82.5%	83.5%	85.2%	85.3%	86.1%	87.0%
EPCOR	65.7%	61.1%	60.7%	62.3%	64.6%	67.5%
ENMAX	60.9%	30.5%	33.4%	38.1%	32.4%	-
Saskatchewan Power	55.7%	56.3%	58.9%	61.0%	64.3%	67.2%
Manitoba Hydro	85.3%	88.1%	89.5%	90.8%	92.4%	93.8%
Ontario Hydro	-	-	111.3%	117.1%	92.6%	87.9%
Ontario Power Generation	38.1%	38.7%	-	-	-	-
Hydro One	53.5%	54.6%	-	-	-	-
Hydro-Quebec	73.6%	73.5%	74.8%	74.8%	75.6%	76.6%
New Brunswick Power	99.7%	99.3%	99.9%	88.6%	88.3%	88.0%
Newfoundland & Labrador Hydro	66.4%	63.1%	65.2%	68.1%	69.4%	70.1%
Churchill Falls	46.7%	49.5%	53.8%	55.2%	56.4%	58.1%
Group Average	69.8%	70.0%	85.6%	86.9%	82.1%	81.8%
Canadian Investor Owned						
UtiliCorp Networks Canada (BC)	62.4%	59.1%	61.3%	59.1%	58.9%	56.8%
ATCO Electric	55.8%	53.2%	55.2%	58.7%	60.8%	63.8%
TransAlta Utilities	57.0%	51.7%	48.1%	49.6%	47.9%	52.9%
Northern Ontario Power	34.5%	34.6%	34.6%	32.8%	32.4%	61.5%
Nova Scotia Power	65.4%	65.8%	67.2%	67.8%	69.0%	68.7%
Group Average	57.4%	55.0%	54.8%	56.0%	56.5%	60.9%
Canadian Industry Average	68.8%	68.7%	83.4%	84.6%	80.2%	80.4%

(1) Sinking funds netted against debt. Includes debt equivalents. Preferred shares and minority interest have been classified as either debt or equity equivalents.

	Year ended December 31					
U.S. Utilities	2000	1999	1998	1997	1996	1995
AES Corporation	71%	62%	60%	55%	50%	52%
Ameren Corporation	47%	44%	44%	45%	44%	44%
American Electric Power Company, Inc. (AEP)	67%	62%	60%	55%	50%	52%
Central and South West Corporation (merged with AEP in June 2000)	merged	61%	58%	57%	56%	59%
Calpine Corporation	54%	63%	79%	79%	75%	94%
Cinergy Corp.	60%	59%	60%	57%	56%	52%
CMS Energy Corp.	69%	67%	66%	64%	63%	66%
Consolidated Edison, Inc.	51%	49%	41%	43%	42%	40%
Constellation Energy Group	53%	51%	50%	53%	52%	48%
Dominion Resources Inc.	65%	60%	52%	59%	49%	49%
DTE Energy Company (DTE)	51%	51%	53%	51%	51%	52%
Duke Energy Corp.	49%	46%	44%	46%	46%	47%
Edison International	82%	71%	62%	62%	52%	51%
Entergy Corp.	53%	48%	49%	57%	53%	51%
Exelon Corporation	66%	--	--	--	--	--
PECO Energy Company (merged with Unicom and became Exelon in Oct 2000)	merged	75%	52%	59%	47%	48%
Unicom Corporation (merged with PECO and became Exelon in Oct 2000)	merged	59%	66%	54%	51%	53%
FirstEnergy Group	60%	60%	61%	63%	54%	50%
GPU, Inc. (agreed to be acquired by FirstEnergy)	64%	67%	55%	60%	51%	n.a.
FPL Group Inc.	47%	40%	34%	40%	40%	45%
Niagara Mohawk (to be acquired by National Grid)	63%	62%	65%	52%	53%	55%
Northeast Utilities	62%	59%	63%	62%	61%	59%
PG&E Corporation	78%	60%	58%	54%	49%	49%
PPL Corporation	71%	72%	64%	49%	50%	51%
Progress Energy Inc.	66%	49%	47%	48%	49%	51%
Public Service Enterprise Group	63%	60%	50%	53%	49%	49%
Reliant Energy	66%	67%	66%	60%	55%	45%
Southern Company	50%	53%	52%	52%	47%	50%
TXU Corporation	70%	68%	67%	57%	58%	59%
Xcel Energy Inc	61%	--	--	--	--	--
New Century Energies (merged with NSP and became Xcel in Aug 2000)	merged	58%	56%	61%	54%	52%
Northern States Power Company (merged with NCE; became Xcel in Aug 2000)	merged	61%	47%	45%	48%	46%
Arithmetic Average	**61%**	**59%**	**56%**	**55%**	**52%**	**52%**

U.S. utilities have stronger balance sheets than Canadian utilities due to the high leverage of government-owned utilities.

Table 24: Fixed-Charges Coverage (times) (1)

Canadian Government Owned	2000	1999	1998	1997	1996	1995
British Columbia Hydro	2.40	1.91	1.64	1.65	1.47	1.18
EPCOR	1.98	1.84	1.92	1.82	1.81	1.74
ENMAX	2.62	3.98	5.15	4.59	2.40	-
Saskatchewan Power	1.85	1.86	1.79	1.68	1.69	1.37
Manitoba Hydro	1.52	1.30	1.19	1.22	1.21	1.15
Ontario Hydro	-	-	1.39	1.13	1.23	1.22
Ontario Power Generation	7.53	4.96	-	-	-	-
Hydro One	2.50	2.45	-	-	-	-
Hydro-Quebec	1.28	1.24	1.18	1.22	1.11	1.06
New Brunswick Power	1.05	1.12	1.13	0.92	0.79	0.74
Newfoundland & Labrador Hydro	1.17	1.51	1.45	1.24	1.17	1.19
Churchill Falls	1.73	1.75	1.68	1.53	1.46	1.50
Group Average	1.72	1.59	1.33	1.24	1.21	1.14
Canadian Investor Owned						
UtiliCorp Networks Canada (BC)	2.27	2.20	2.22	2.70	2.71	2.47
ATCO Electric	2.52	2.47	2.41	2.22	2.03	2.00
TransAlta Utilities	2.05	2.10	2.75	2.49	2.99	2.66
Northern Ontario Power	2.34	2.81	1.44	2.06	2.20	2.19
Nova Scotia Power	1.98	1.93	1.78	1.82	1.62	1.49
Group Average	2.17	2.17	2.29	2.20	2.25	2.06
Canadian Industry Average	1.75	1.63	1.38	1.29	1.27	1.20

(1) Before capitalized interest, AFUDC, debt amortizations and retractable pfd dividends.

	Year ended December 31					
U.S. Utilities	2000	1999	1998	1997	1996	1995
AES Corporation	1.23	1.36	1.46	1.37	1.88	2.04
Ameren Corporation	5.27	4.92	4.66	4.38	4.52	4.61
American Electric Power Company, Inc. (AEP)	2.02	2.33	2.80	3.05	2.99	2.53
Central and South West Corporation (merged with AEP in June 2000)	merged	2.41	2.37	2.11	2.20	2.47
Calpine Corporation	2.54	1.75	1.66	1.65	1.57	1.38
Cinergy Corp.	3.61	2.91	2.31	3.03	2.80	2.83
CMS Energy Corp.	1.30	1.51	1.58	1.74	1.94	2.00
Consolidated Edison, Inc.	3.39	3.94	4.13	3.92	3.97	3.76
Constellation Energy Group	2.97	3.12	2.73	2.51	2.38	2.45
Dominion Resources Inc.	2.13	2.59	1.98	2.40	2.93	2.75
DTE Energy Company (DTE)	2.29	2.45	2.64	2.91	3.01	3.03
Duke Energy Corp.	3.83	4.62	4.82	3.61	4.05	3.74
Edison International	-0.96	1.87	1.74	2.58	2.81	3.02
Entergy Corp.	3.37	2.76	1.93	1.55	2.68	2.43
Exelon Corporation	3.01	--	--	--	--	--
PECO Energy Company (merged with Unicom and became Exelon in Oct 2000)	merged	3.52	4.70	3.25	3.96	3.84
Unicom Corporation (merged with PECO and became Exelon in Oct 2000)	merged	2.49	2.32	1.84	2.70	2.72
FirstEnergy Group	2.06	2.00	1.76	2.06	2.22	2.09
GPU, Inc. (agreed to be acquired by FirstEnergy)	1.91	1.02	1.02	1.02	1.02	n.a.
FPL Group Inc.	4.80	5.28	3.72	3.77	3.68	3.30
Niagara Mohawk (to be acquired by National Grid)	1.51	1.56	1.33	1.66	1.60	1.83
Northeast Utilities	2.10	1.80	1.11	0.59	1.28	2.29
PG&E Corporation	-5.79	2.92	2.81	2.82	3.57	4.19
PPL Corporation	3.07	2.84	3.71	3.61	3.87	3.52
Progress Energy Inc.	2.73	4.03	4.31	4.28	4.42	4.00
Public Service Enterprise Group	2.76	3.13	2.80	2.58	2.64	2.77
Reliant Energy	2.47	2.23	2.49	2.81	3.04	2.62
Southern Company	2.35	2.38	2.78	2.58	3.17	3.23
TXU Corporation	1.72	1.87	1.84	2.16	2.24	2.25
Xcel Energy Inc	2.23	--	--	--	--	--
New Century Energies (merged with NSP and became Xcel in Aug 2000)	merged	3.06	3.12	3.14	3.56	3.41
Northern States Power Company (merged with NCE; became Xcel in Aug 2000)	merged	3.44	4.06	3.70	3.89	3.45
Arithmetic Average	2.22	2.74	2.69	2.62	2.89	2.92

Note: The average for U.S. utilities in 2000 is distorted by the losses at Edison and PG&E. Excluding these two utilities, the average was 2.67 times in 2000 compared to 2.74 times in 1999.

Table 25: EBIT Interest Coverage (times) (1)

Canadian Government Owned	2000	1999	1998	1997	1996	1995
British Columbia Hydro	2.40	1.91	1.64	1.65	1.47	1.18
EPCOR	1.98	1.84	1.92	1.82	1.81	1.74
ENMAX	2.62	3.98	5.15	4.59	2.40	-
Saskatchewan Power	1.85	1.86	1.79	1.68	1.69	1.37
Manitoba Hydro	1.52	1.30	1.19	1.22	1.21	1.15
Ontario Hydro	-	-	1.39	1.13	1.23	1.22
Ontario Power Generation	7.53	4.96	-	-	-	-
Hydro One	2.50	2.45	-	-	-	-
Hydro-Quebec	1.28	1.24	1.18	1.22	1.11	1.06
New Brunswick Power	1.05	1.12	1.13	0.92	0.79	0.74
Newfoundland & Labrador Hydro	1.17	1.51	1.45	1.24	1.17	1.19
Churchill Falls	1.73	1.75	1.68	1.53	1.46	1.50
Group Average	1.72	1.59	1.33	1.24	1.21	1.14
Canadian Investor Owned						
UtiliCorp Networks Canada (BC)	2.27	2.20	2.22	2.70	2.72	2.48
ATCO Electric	2.94	3.01	3.19	3.01	2.89	2.90
TransAlta Utilities	2.49	2.78	3.59	3.19	4.02	3.75
Northern Ontario Power	2.34	2.81	1.44	2.06	2.20	2.19
Nova Scotia Power	2.30	2.28	2.08	2.07	1.89	1.75
Group Average	2.53	2.65	2.85	2.70	2.85	2.67
Canadian Industry Average	1.79	1.67	1.41	1.32	1.30	1.23

(1) Before capitalized interest, AFUDC, debt amortizations and retractable preferred dividends.

	Year ended December 31					
U.S. Utilities	2000	1999	1998	1997	1996	1995
AES Corporation	1.24	1.36	1.46	1.37	1.88	2.04
Ameren Corporation	5.27	4.92	4.66	4.38	4.52	4.61
American Electric Power Company, Inc. (AEP)	2.05	2.4	2.91	3.25	3.48	3.05
Central and South West Corporation (merged with AEP in June 2000)	merged	2.55	2.47	2.44	2.49	2.41
Calpine Corporation	2.64	1.82	1.71	1.69	1.61	1.39
Cinergy Corp.	3.86	3.14	2.48	3.37	3.33	3.5
CMS Energy Corp.	1.60	1.76	1.93	2.11	2.37	2.32
Consolidated Edison, Inc.	3.56	4.19	4.46	4.25	4.35	4.38
Constellation Energy Group	3.22	3.4	3.12	2.99	3.04	3.17
Dominion Resources Inc.	2.13	2.61	2	2.41	2.93	2.75
DTE Energy Company (DTE)	2.42	2.6	2.89	3.31	3.52	3.69
Duke Energy Corp.	3.40	4.03	4.32	4.23	4.32	4.49
Edison International	-1.09	2.1	1.88	2.83	3.14	3.42
Entergy Corp.	2.95	3.15	2.11	1.88	2.35	1.94
Exelon Corporation	3.06	--	--	--	--	--
PECO Energy Company (merged with Unicom and became Exelon in Oct 2000)	merged	3.69	4.99	3.48	4.25	4.18
Unicom Corporation (merged with PECO and became Exelon in Oct 2000)	merged	2.66	2.79	2.20	3.23	3.25
FirstEnergy Group	3.05	3.02	2.48	2.90	3.20	2.90
GPU, Inc. (agreed to be acquired by FirstEnergy)	2.13	2.97	3.00	2.89	2.96	n.a.
FPL Group Inc.	5.32	5.90	4.02	4.18	4.24	4.10
Niagara Mohawk (to be acquired by National Grid)	1.70	1.77	1.54	2.07	1.99	2.29
Northeast Utilities	2.26	2.03	1.26	0.69	1.51	2.72
PG&E Corporation	-5.79	2.92	2.81	2.82	3.57	4.19
PPL Corporation	3.07	2.84	3.71	3.61	3.87	3.52
Progress Energy Inc.	2.78	4.22	4.50	4.49	4.65	4.19
Public Service Enterprise Group	3.24	3.78	3.32	2.93	2.98	3.10
Reliant Energy	2.79	2.60	2.74	3.14	3.39	3.04
Southern Company	3.44	3.75	4.15	3.45	4.07	4.10
TXU Corporation	1.94	2.05	2.04	2.48	2.51	2.57
Xcel Energy Inc	2.64	--	--	--	--	--
New Century Energies (merged with NSP and became Xcel in Aug 2000)	merged	3.10	3.26	3.18	3.81	3.93
Northern States Power Company (merged with NCE; became Xcel in Aug 2000)	merged	3.64	4.39	4.23	4.28	4.01
Arithmetic Average	2.40	3.03	2.98	2.98	3.26	3.28

Excluding Edison and PG&E, average EBIT interest coverage for the U.S. utilities in 2000 was 2.87 times.

Table 26: Cash Flow (1) /Total Debt (times)

Canadian Government Owned	2000	1999	1998	1997	1996	1995
British Columbia Hydro	0.13	0.13	0.11	0.11	0.09	0.07
EPCOR	0.14	0.15	0.17	0.17	0.15	0.13
ENMAX	0.14	0.51	0.59	0.45	0.30	-
Saskatchewan Power	0.18	0.17	0.17	0.17	0.16	0.11
Manitoba Hydro	0.08	0.06	0.06	0.06	0.06	0.05
Ontario Hydro	-	-	0.09	0.07	0.07	0.07
Ontario Power Generation	0.27	0.28	-	-	-	-
Hydro One	0.15	0.15	-	-	-	-
Hydro-Quebec	0.08	0.07	0.06	0.06	0.05	0.04
New Brunswick Power	0.07	0.08	0.08	0.05	0.04	0.04
Newfoundland & Labrador Hydro	0.06	0.11	0.09	0.06	0.04	0.04
Churchill Falls	0.14	0.14	0.12	0.10	0.09	0.09
Group Average	0.11	0.10	0.08	0.07	0.07	0.06
Canadian Investor Owned						
UtiliCorp Networks Canada (BC)	0.10	0.11	0.11	0.13	0.14	0.17
ATCO Electric	0.18	0.20	0.19	0.17	0.16	0.14
TransAlta Utilities	0.26	0.21	0.25	0.26	0.28	0.25
Northern Ontario Power	0.13	0.13	0.07	0.12	0.12	0.12
Nova Scotia Power	0.14	0.13	0.12	0.12	0.11	0.08
Group Average	0.18	0.17	0.17	0.18	0.17	0.15
Canadian Industry Average	0.12	0.11	0.08	0.08	0.07	0.06

(1) Cash flow before working capital, after all preferred dividends.

	Year ended December 31					
U.S. Utilities	2000	1999	1998	1997	1996	1995
AES Corporation	0.05	0.05	0.03	0.05	0.09	0.16
Ameren Corporation	0.26	0.25	0.26	0.25	0.26	0.26
American Electric Power Company, Inc. (AEP)	0.09	0.09	0.13	0.21	0.24	0.21
Central and South West Corporation (merged with AEP in June 2000)	merged	0.17	0.17	0.16	0.19	0.15
Calpine Corporation	0.11	0.10	0.12	0.12	0.08	0.09
Cinergy Corp.	0.18	0.12	0.18	0.16	0.15	0.22
CMS Energy Corp.	0.07	0.11	0.11	0.14	0.17	0.16
Consolidated Edison, Inc.	0.22	0.24	0.30	0.25	0.27	0.28
Constellation Energy Group	0.22	0.24	0.21	0.20	0.22	0.23
Dominion Resources Inc.	0.12	0.15	0.16	0.13	0.16	0.21
DTE Energy Company (DTE)	0.23	0.25	0.20	0.24	0.26	0.26
Duke Energy Corp.	0.21	0.25	0.29	0.27	0.32	0.28
Edison International	0.02	0.08	0.15	0.22	0.25	0.23
Entergy Corp.	0.19	0.15	0.20	0.15	0.19	0.18
Exelon Corporation	0.14	--	--	--	--	--
PECO Energy Company (merged with Unicom and became Exelon in Oct 2000)	merged	0.18	0.36	0.26	0.26	0.26
Unicom Corporation (merged with PECO and became Exelon in Oct 2000)	merged	0.14	0.16	0.23	0.24	0.26
FirstEnergy Group	0.18	0.18	0.14	0.09	0.22	0.23
GPU, Inc. (agreed to be acquired by FirstEnergy)	0.14	0.03	0.15	0.13	0.20	n.a.
FPL Group Inc.	0.22	0.36	0.59	0.47	0.42	0.34
Niagara Mohawk (to be acquired by National Grid)	0.12	0.12	0.10	0.15	0.14	0.18
Northeast Utilities	0.15	0.14	0.17	0.07	0.16	0.20
PG&E Corporation	0.02	0.13	0.16	0.23	0.23	0.28
PPL Corporation	1.33	1.72	1.32	1.55	1.52	0.97
Progress Energy Inc.	0.09	0.28	0.34	0.35	0.35	0.35
Public Service Enterprise Group	0.14	0.16	0.23	0.19	0.24	0.27
Reliant Energy	0.17	0.11	0.14	0.16	0.20	0.25
Southern Company	0.26	0.27	0.17	0.18	0.24	0.21
TXU Corporation	0.11	0.12	0.12	0.15	0.17	0.16
Xcel Energy Inc	0.15	--	--	--	--	--
New Century Energies (merged with NSP and became Xcel in Aug 2000)	merged	0.27	0.27	0.28	0.31	0.29
Northern States Power Company (merged with NCE; became Xcel in Aug 2000)	merged	0.17	0.29	0.28	0.27	0.30
Arithmetic Average	0.19	0.22	0.24	0.24	0.27	0.26

In 2000, cash flow/total debt was helped by earnings improvements in Canada. The higher debt levels in Canada have a negative impact on this ratio.

Table 27: Total Electricity Sales - million kWhs

Canadian Government Owned	2000	1999	1998	1997	1996	1995
British Columbia Hydro	72,031	69,852	64,506	56,460	54,484	46,822
EPCOR	10,013	9,147	9,858	8,180	8,305	7,703
ENMAX (1)	7,500	7,162	6,980	6,867	6,644	-
Saskatchewan Power	17,049	16,225	16,187	15,608	15,064	14,383
Manitoba Hydro	28,734	26,688	27,692	29,462	27,567	25,460
Ontario Hydro	-	-	138,914	139,727	137,770	140,850
Ontario Power Generation	139,800	136,900	-	-	-	-
Hydro One (1)	17,600	18,100	-	-	-	-
Hydro-Quebec	190,080	171,712	161,373	162,533	163,546	166,101
New Brunswick Power	18,889	19,842	20,597	18,577	16,804	17,338
Newfoundland & Labrador Hydro	8,206	7,988	7,598	6,781	6,589	6,506
Churchill Falls	34,601	33,807	36,878	33,131	28,411	29,450
Canadian Investor Owned						
UtiliCorp Networks Canada (BC)	2,717	2,646	2,617	2,628	2,759	2,623
ATCO Electric	9,983	9,668	9,790	9,687	9,351	8,493
TransAlta Utilities	28,636	27,560	27,672	28,463	27,844	28,380
Northern Ontario Power	2,309	2,341	2,378	2,313	2,270	2,125
Nova Scotia Power	10,656	10,365	9,772	9,516	9,146	9,035

(1) Represents distribution sales. Excluded from all totals.

Water availability is an important determinant of electricity generated in Canada.

	Year ended December 31					
U.S. Utilities	2000	1999	1998	1997	1996	1995
AES Corporation	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Ameren Corporation	72,385	66,776	61,445	63,981	64,436	61,111
American Electric Power Company, Inc. (AEP)	206,281	128,868	197,346	197,362	194,998	n.a.
Central and South West Corporation (merged with AEP in June 2000)	merged	66,802	66,994	63,157	62,425	59,934
Calpine Corporation	22,750	14,803	9,864	2,158	1,985	1,034
Cinergy Corp.	119,958	99,824	124,742	102,781	57,520	51,842
CMS Energy Corp.	40,986	41,042	40,049	37,898	37,051	35,506
Consolidated Edison, Inc.	40,530	43,997	40,329	40,027	41,121	41,993
Constellation Energy Group	34,978	34,049	34,221	34,323	36,010	36,341
Dominion Resources Inc.	73,516	70,605	68,784	66,585	66,773	66,773
DTE Energy Company (DTE)	55,000	55,524	54,913	50,642	48,453	48,942
Duke Energy Corp.	84,766	81,548	82,011	77,935	77,547	77,126
Edison International	82,936	78,602	76,595	77,234	75,572	74,296
Entergy Corp.	113,010	110,233	111,411	106,820	106,909	103,465
Exelon Corporation	181,052	--	--	--	--	--
PECO Energy Company (merged with Unicom and became Exelon in Oct 2000)	merged	78,064	74,864	63,857	54,123	48,531
Unicom Corporation (merged with PECO and became Exelon in Oct 2000)	merged	102,988	95,157	95,504	91,275	91,353
FirstEnergy Group	72,700	67,076	62,421	63,750	64,946	63,790
GPU, Inc. (agreed to be acquired by FirstEnergy)	51,004	51,504	47,355	45,868	44,448	45,753
FPL Group Inc.	91,969	88,067	89,362	82,734	80,889	79,756
Niagara Mohawk (to be acquired by National Grid)	46,765	43,111	41,003	37,136	39,127	37,684
Northeast Utilities	75,660	66,848	41,842	39,584	39,474	39,618
PG&E Corporation	81,923	79,230	77,884	79,378	74,394	75,359
PPL Corporation	51,455	64,760	68,852	53,418	46,648	42,705
Progress Energy Inc.	59,665	54,759	54,476	52,765	51,328	49,890
Public Service Enterprise Group	40,620	41,132	40,739	38,376	41,473	40,283
Reliant Energy	75,294	72,107	72,733	67,078	64,710	61,076
Southern Company	176,947	166,313	164,335	156,887	153,531	146,207
TXU Corporation	106,670	100,548	103,142	97,023	95,254	89,028
Xcel Energy Inc	106,978	--	--	--	--	--
New Century Energies (merged with NSP and became Xcel in Aug 2000)	merged	52,151	54,592	49,013	47,421	44,765
Northern States Power Company (merged with NCE; became Xcel in Aug 2000)	merged	43,803	42,835	40,013	39,762	41,000

The mergers taking place in the U.S. are creating fewer, but larger companies.

Table 28: Average Retail Revenues - cents/kWh sold

Canadian Government Owned	2000	1999	1998	1997	1996	1995
British Columbia Hydro	4.93	4.95	4.93	4.98	4.96	4.91
EPCOR	6.50	6.62	6.68	6.90	6.92	7.04
ENMAX	9.18	6.68	6.59	6.48	6.53	0.00
Saskatchewan Power	6.14	6.08	6.04	6.00	6.06	5.97
Manitoba Hydro	4.69	4.67	4.59	4.65	4.67	4.65
Ontario Hydro	-	-	6.27	6.33	6.39	6.42
Ontario Power Generation	4.11	4.04	-	-	-	-
Hydro-Quebec	5.10	5.07	5.04	4.98	4.89	4.89
New Brunswick Power	6.64	6.54	6.44	6.30	6.23	6.07
Newfoundland & Labrador Hydro	4.30	4.44	4.36	4.30	4.35	4.38
Churchill Falls	0.17	0.18	0.16	0.14	0.14	0.14
Group Average	5.07	5.00	5.51	5.52	5.50	5.49
Canadian Investor Owned						
UtiliCorp Networks Canada (BC)	4.96	4.72	4.71	4.67	4.53	4.46
ATCO Electric	6.64	5.67	5.59	5.59	5.35	5.59
TransAlta Utilities	2.59	4.20	4.14	3.87	4.24	4.82
Northern Ontario Power	5.36	5.36	5.34	5.38	5.41	5.39
Nova Scotia Power	7.63	7.62	7.68	7.79	7.99	7.88
Group Average	4.56	5.22	5.16	5.00	5.18	5.50
Canadian Industry Average	5.48	5.52	5.48	5.46	5.48	5.46

	Year ended December 31					
U.S. Utilities	2000	1999	1998	1997	1996	1995
AES Corporation	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Ameren Corporation	5.99	6.13	6.16	6.13	6.17	6.28
American Electric Power Company, Inc. (AEP)	5.39	4.98	4.99	4.89	4.93	4.97
Central and South West Corporation (merged with AEP in June 2000)	merged	5.12	5.06	5.38	5.41	5.20
Calpine Corporation	--	--	--	--	--	--
Cinergy Corp.	6.23	6.10	5.43	5.42	5.40	5.41
CMS Energy Corp.	6.61	6.68	6.90	6.94	6.89	6.59
Consolidated Edison, Inc.	15.92	13.63	13.80	14.07	13.97	13.55
Constellation Energy Group	6.80	7.24	7.21	7.25	7.13	7.25
Dominion Resources Inc.	6.18	6.05	5.85	6.42	6.35	6.56
DTE Energy Company (DTE)	7.60	7.59	7.52	7.53	7.68	n.a.
Duke Energy Corp.	5.56	5.51	5.49	5.50	5.54	5.60
Edison International	8.90	9.09	9.36	10.13	9.93	10.67
Entergy Corp.	6.38	5.75	5.80	6.22	6.24	6.06
Exelon Corporation	8.35	--	--	--	--	--
PECO Energy Company (merged with Unicom and became Exelon in Oct 2000)	merged	9.60	9.90	10.23	10.11	10.07
Unicom Corporation (merged with PECO and became Exelon in Oct 2000)	merged	7.40	8.07	8.40	8.39	8.30
FirstEnergy Group	7.82	8.18	8.35	8.33	n.a.	n.a.
GPU, Inc. (agreed to be acquired by FirstEnergy)	7.35	7.51	8.52	9.07	8.93	8.81
FPL Group Inc.	6.89	6.91	7.16	7.40	7.40	6.99
Niagara Mohawk (to be acquired by National Grid)	9.17	9.02	9.20	9.31	9.36	9.32
Northeast Utilities	10.29	10.44	10.60	10.92	10.79	8.60
PG&E Corporation	8.14	8.99	9.08	9.61	9.96	10.20
PPL Corporation	6.18	6.11	7.22	7.36	7.42	7.22
Progress Energy Inc.	6.37	6.27	6.32	6.31	6.37	6.49
Public Service Enterprise Group	8.67	9.61	9.74	10.00	9.76	9.97
Reliant Energy	6.70	6.44	6.37	6.38	6.26	6.08
Southern Company	5.74	5.62	5.85	5.74	5.81	5.96
TXU Corporation	4.47	4.47	4.49	4.51	4.61	4.62
Xcel Energy Inc	5.55	--	--	--	--	--
New Century Energies (merged with NSP and became Xcel in Aug 2000)	merged	5.24	5.39	5.38	5.42	5.44
Northern States Power Company (merged with NCE; became Xcel in Aug 2000)	merged	5.85	5.89	5.81	5.71	5.72
Arithmetic Average	7.33	7.20	7.35	7.52	7.48	7.38

Average retail prices remained relatively unchanged in both Canada and the U.S. in 2000. This in unlikely to change in 2001.

British Columbia Hydro and Power Authority

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

Current Report: September 5, 2001
Previous Report: September 8, 2000

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RATING*

Rating	Trend	Rating Action	Debt Rated
AA (low)	Stable	Confirmed	Long-term Liabilities

RATING HISTORY

	Current	2000	1999	1998	1997	1996	1995
Long-term Liabilities	AA (low)	AA (low)	AA (low)	AA	AA	AA	AA

UPDATE

DBRS confirms British Columbia Hydro & Power Authority's ("BC Hydro" or "the Utility") long-term liabilities at AA (low) with a Stable trend. BC Hydro's rating is a flow-through of the Province of British Columbia's rating, as the Utility's debt securities are direct obligations of the province. BC Hydro had a record year in 2000-01, far exceeding the performance in any other one-year period. The two main factors contributing to this performance were: (1) record high prices for power in California and the western U.S., as well as in Alberta; and (2) good returns from trading power, taking advantage of purchasing at off-peak rates and delivering electricity at on-peak prices, aided by the storage capability of its hydro base. This record performance occurred despite: (1) a 9% decline in the volume of hydro-produced electricity due to water shortages; (2) sharply higher natural gas and oil prices for the 10% of the Utility's electricity produced from thermal sources; (3) a DBRS-estimated $200 million provision for uncollectable receivables of two California-based utilities; and (4) a $310 million rebate paid to residential tariff customers, West Kootenay Power and the City of New Westminster. While revenues will be down in 2002, due to lower water levels caused by drought and subsequently reduced electricity prices, earnings should remain respectable. The balance sheet strengthened in 2001, reflecting the record earnings. However, the one-time $310 million rebate prevented even greater improvements. Debt levels near 80% are high, but strong cash flow led to a cash-flow/net-debt near 0.15, which is in the range of investor-owned held North American companies with 50%-60% debt. The Utility also has excellent flexibility. Stress testing indicates that, even with earnings falling to $500 million per year, the Utility should still generate close to $900 million in excess operating cash flow over the next three years. This excess could be used to repay debt and improve the balance sheet. BC Hydro's primary long-term strength remains its 10,000 MW of hydro-based generation capacity.

CONSIDERATIONS

Strengths:

- Debt securities are direct obligations of the Province
- Low-cost hydro-based generating facilities with substantial storage capacity
- U.S. FERC marketing license enhances access to U.S. markets as well as earnings growth potential
- Sufficient cash flows to finance capital expenditures and dividend payments
- Interconnection with U.S. and Alberta

Challenges:

- Excessive debt levels constrain profitability
- Exposure to currency exchange rates: 50% of debt is foreign dollar denominated, of which 65% is unhedged
- Earnings sensitive to water levels
- Heavy government levy burden
- Economic growth is expected to slow

FINANCIAL INFORMATION

	For years ended March 31						
	2001	2000	1999	1998	1997	1996	1995
EBIT interest coverage (times)	2.40	1.91	1.64	1.65	1.47	1.18	1.21
Net debt in the capital structure (1)	81.0%	83.5%	85.1%	85.3%	86.0%	87.0%	87.4%
Cash flow/net debt (times)	0.148	0.130	0.098	0.098	0.081	0.052	0.050
Cash flow/capital expenditures (times)	2.78	2.58	2.12	2.55	2.20	1.27	1.07
Net income (bef. extras.) ($ millions)	859	545	407	440	358	150	185
Operating cash flow ($ millions)	919	912	733	708	598	398	392
Electricity sales (millions of kWhs)	72,031	69,852	64,506	56,460	54,484	46,822	46,981
Electricity revenues (cents per kWh sold)	10.87	4.91	4.65	4.42	4.36	4.77	4.81
Variable costs (cents per net gen kWh sold)	2.52	1.10	1.10	0.89	0.91	1.15	1.22
Fixed costs (cents per net gen kWh sold)	1.90	2.01	2.17	2.89	2.89	3.54	3.53
Average coupon on long-term debt	7.80%	8.10%	7.70%	8.50%	8.50%	9.40%	10.00%

(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 British Columbia. BC Hydro is the third largest public electric utility in Canada.

REGULATIONS

BC Hydro is regulated by the British Columbia Utilities Commission, which establishes and approves customer rates, allowed rates of return and annual payments to the Province. Both the Utility and the Utilities Commission are subject to directives issued by the Province of British Columbia. The approved ROE is set at a rate equivalent to the pre-tax return allowed for investor-owned utilities. The approved pre-tax ROE for the years ended March 31, 2001 and 2000 was 16.69% versus 17.47% in 1999. 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 the Utility’s debt to equity ratio after deducting the payment does not exceed 80:20. (The calculation includes customer contributions, Columbia River Treaty contributions and deferred revenues as equity equivalents. However, DBRS excludes all of these items in its debt ratios, consistent with the treatment accorded other utilities.) 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 30, 2003.

CONSIDERATIONS

Strengths: (1) *Debt securities are direct obligations of the provincial government*. As such, the rating assigned to BC Hydro is a flow-through of the rating of the Province of British Columbia.

(2) *Hydro-based generating facilities with substantial storage capacity* - The Utility’s generating capacity is largely low cost hydro-based and contributes to one of the lowest variable cost structures in North America. Variable costs under 1¢ per KWh for hydro based power make BC Hydro very competitive. Given the water storage capacity of its hydro-based power generating facilities, BC Hydro is in an excellent position to trade power, buying low cost power during off-peak hours, and selling its own generated power during peak periods at higher rates.

(3) *U.S. FERC marketing license* - In 1996, the Utility’s export subsidiary, Powerex, was granted a power marketing license from the U.S. Federal Energy Regulatory Commission (FERC). This has expanded the size of BC Hydro’s potential export market, as the Utility is now able to sell power directly to other utilities in the U.S., rather than only conducting business at the Canadian-U.S. border. Improved access to U.S. markets should enhance earnings growth potential over the longer-term, but also exposes the BC Hydro to potentially material market risks.

(4) *Interconnection with Alberta and U.S.* - Interconnections with other utilities include a 600 MW inter-tie to power short Alberta, and a 3,150 MW inter-tie to the Pacific Northwest U.S. - a market with a high cost of generation.

(5) *Sufficient cash flows to finance capital expenditures and dividend payments.*

Challenges: (1) *Excessive debt levels constrain profitability* - With a debt-to-capital ratio of 81%, BC Hydro has one of the highest debt burdens of all utilities in Canada. Although the refinancing of high coupon debt at lower rates has materially reduced interest costs, the high debt level substantially weakens profitability ratios as net interest expenses still account for roughly 60% of earnings. The average coupon on long-term debt has fallen to 7.80%.

(2) *Exposure to currency exchange rates* - The Utility is sensitive to exchange rates as foreign (mostly U.S.) dollars denominated debt issues account for 45% of total debt outstanding at the end of F2001. Currency swaps reduced this exposure to roughly 32% of total debt outstanding.

(3) *Earnings are sensitive to water levels* - Given the hydro-based nature of its generating facilities. This can contribute to fluctuations in earnings and interest coverage ratios over the shorter-term and can potentially affect export sales.

(4) *Heavy government levy burden* - BC Hydro has among the highest government levy burdens (taxes, debt guarantee fees and dividends payments) of all government-owned utilities with 60%-95% of earnings over the last five years returned to the provincial government.

(5) *Economic growth is expected to slow* - Although BC’s economy posted its fasted growth in seven years (3.8%) in 2000, economic growth is expected to gear down for the remainder of 2001-02 (growth forecast at 2.2%). The outlook of the year reflects: (a) a longer slowdown of the U.S. economy; (b) a broad-based weakening in commodity prices; and (c) weak prospects for the Japanese economy, expected to shrink 0.5% in 2001.

REVENUES

Customer Sector	Revenues - $ millions			Energy Sales - billions of kWh			Unit Revenues - cents/kWh sold		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
Residential	892	894	855	14.537	14.599	13.987	6.14	6.12	6.11
Light industrial + commercial	866	849	838	16.292	15.960	15.776	5.32	5.32	5.31
Large industrial	524	482	488	15.573	14.644	14.705	3.36	3.29	3.32
Other	90	73	77	1.729	1.239	1.323	5.21	5.89	5.82
Total domestic electric	2,372	2,298	2,258	48.131	46.442	45.791	4.93	4.95	4.93
Trading volumes	5,458	1,129	739	23.900	23.410	18.715	22.84	4.82	3.95
Total sold	7,830	3,427	2,997	72.031	69.852	64.506	10.87	4.91	4.65
Annual Change	128.5%	14.3%	20.0%	3.1%	8.3%	14.3%			

The 128.5% revenue growth in 2000-01 was led primarily by its 383% increase in energy trading revenues. Actual export volumes to neighbouring Alberta and the northwestern U.S., however, only increased by 2.1%. Domestic revenues increased 3.2% and domestic energy sales volumes increased 3.6%.

EARNINGS

($ millions)	2001	2000	1999	1998	1997	1996	1995	1994
Revenues	7,889	3,480	3,043	2,554	2,426	2,294	2,299	2,198
EBITDA	1,916	1,578	1,466	1,497	1,481	1,389	1,373	1,356
EBIT	1,536	1,203	1,119	1,155	1,154	1,077	1,081	1,056
Net interest expense	559	579	615	585	625	746	724	679
Net income before extraordinary items	859	545	407	440	358	150	185	190
Net income	446	416	395	408	339	150	162	190

In 2000-01, BC Hydro had the best year in its history, despite the fact that hydro power generated was down by 9%. The two main factors contributing to this performance were: (1) record high prices for power in California and the western U.S., as well as in Alberta; and (2) good returns from trading volume in the export markets. Along with the 9% decrease in hydro generation, three other factors restricted income. (1) While generation of electricity from gas yielded good returns as power from this source tripled, gas prices increased significantly in 2000 and margins earned from this source were much lower than from hydro. (2) A bad debt provision on sales made by BC Hydro to two California utilities estimated by DBRS to be near $200 million. (3) BC Hydro was ordered by the government to rebate $310 million to West Kootenay Power and New Westminster, two important customers. Before bad debt and customer extras, the Utility would have earned in excess of $1 billion in what was easily the most successful year ever for the Utility.

Outlook: With substantially lower water levels and sharply reduced electricity rates, earnings for the year ended March 31, 2002, will likely be substantially reduced to levels closer to the $500 million - $600 million range, as more normal conditions prevail. The Utility is also becoming a strong "trading" company, buying off-peak power and selling power at the higher on-peak rates.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

	Actual		Stress Testing		
($ millions)	2001	2000	Year 1	Year 2	Year 3
Net income before transfers	859	545	500	500	500
Depreciation/amortization	380	375	400	410	420
Operating cash flow	1,239	920	900	910	920
Less: capex (net of contrib.)	331	354	300	300	300
Less: dividends paid	372	343	325	325	325
Gross free cash	536	223	275	285	295
Plus/minus: working capital	(659)	(118)	0	0	0
Net free cash flow	(123)	105	275	285	295
Change in net debt	(791)	(486)	(275)	(285)	(295)
% net debt in capital structure	81.0%	83.5%	78.4%	75.8%	73.0%
EBIT interest coverage (times) (1)	2.40	1.91	2.08	2.05	2.04
Cash flow/net debt	14.8%	13.0%	15.2%	16.1%	17.2%

Financial Profile:
A $310 million payout to two large customers prevented further improvements to the 2001 balance sheet. Without the $310 million cash outlay, debt could have been reduced by an equivalent amount. Strong cash flow enabled the Utility to attain a cash flow/debt ratio of 0.148. This is close to the level of the private sector and, with BC Hydro's 81% net debt levels, is really quite exceptional (an indication of the substantial cash flow earned during the period).

Sensitivity Analysis:
In stress testing, DBRS assumed that capital expenditures will decrease to $300 million annually and income will level off near $500 million. Dividends and payments to the government were assumed to remain constant near $300 million. On this basis, the Utility would be able to generate free cash flow of close to $300 million per year which could be used to pay down debt and lead to a continuous strengthening of the balance sheet. BC Hydro will require additional generating capacity by 2007, and the stress testing assumes that much of this expansion will be carried out by the private sector. The Utility, over three years, is expected to generate about $860 million in excess cash, which could be used to increase payments to the government or increase capital expenditures. Whatever choices the Utility makes, it will have substantial flexibility with its future balance sheet.

Debt Maturity Schedule

BC Hydro has a well distributed debt maturity schedule over the next five years. Debt maturity schedule is as follows:

	F2002	F2003	F2004	F2005	F2006
($ millions)	404	441	300	514	483

Province of British Columbia

The Province of British Columbia's ("the Province") long-term and short-term ratings were confirmed at AA (low) and R-1 (middle), respectively, both with Stable trends. The confirmation of the rating reflects: (1) the relatively low debt burden of the Province (21.8% of GDP); (2) the commitment of the new government to re-establish fiscal discipline; and (3) renewed efforts to improve the business climate. The Province also benefits from a large and diversified natural resource base, which is expected to continue to generate important revenues in 2001-02 ($3.8 billion). However, aggressive tax cuts and sustained spending pressures are expected to result in substantially weaker fiscal results in the short run. This is reflected in the $2.6 billion DBRS-adjusted deficit projected for 2001-02. Despite their long-term positive impact on economic activity, the large tax cuts recently announced have substantially reduced fiscal revenues. Making up for the lost revenues may prove to be a challenge for the Province, especially if the prospects for the North American economy continue to weaken. Controlling spending will also be essential to achieving balanced budgets, required by 2004-05 under the *Balanced Budget and Ministerial Accountability Act*. Program spending has been increasing rapidly in recent years, fuelled by increasing demand for health services and rising wages, which account for more than 60% of provincial ministry expenditures. As a result, substantial deficits are likely to be posted over the next three years. Other challenges include changing the historical perception of businesses with respect to British Columbia's investment climate and managing the volatility of the natural resource revenues. The latter has been growing rapidly in importance in recent years and can cause large swings in fiscal balances, as energy and forestry royalties may be quite volatile.

British Columbia Hydro & Power Authority

Balance Sheet
($ millions)

Assets	2001	2000	1999	**Liabilities & Equity**	2001	2000	1999
	As at March 31				As at March 31		
Temporary investments	686	5	33	Accounts payable	1,121	472	323
A/R + unbilled revenues	345	407	412	Accrued int & div pmt	496	469	454
Supplies + prepaids	163	151	166	Long-term debt due in 1 yr.	415	699	1,354
Unrealized gains on mark-to-market	113	8	0	Unreal. loss mark-to-mkt.	108	8	0
Current assets	1,307	571	611	Current liabilities	2,140	1,648	2,131
Net fixed assets	9,361	9,320	9,236	Long-term debt	7,633	7,328	7,125
Sinking funds	1,148	1,017	955	Rate stab. acct.	232	129	0
Demand-side mgmt programs	116	146	176	Def'd rev. + liab.	370	327	338
Deferred debt costs	633	500	634	Columbia River Treaty	221	230	240
Investments	0	0	4	Customer contribution	560	549	539
Foreign currency contracts	50	42	69	Common equity	1,459	1,385	1,312
Total	12,615	11,596	11,685	Total	12,615	11,596	11,685

Ratio Analysis

	For years ended March 31							
Liquidity Ratios	2001	2000	1999	1998	1997	1996R	1995R	1994R
Current ratio	0.61	0.35	0.29	0.38	0.62	0.73	0.72	0.74
Accumulated depreciation/gross fixed assets	36.0%	34.8%	33.6%	32.5%	31.3%	30.2%	29.0%	28.1%
Cash flow / net debt	0.148	0.130	0.098	0.098	0.081	0.052	0.050	0.051
Cash flow / capital expenditures (1)	2.78	2.58	2.12	2.55	2.20	1.27	1.07	1.05
Cash flow-dividends / capital expenditures (1)	1.65	1.61	1.18	1.23	1.17	0.90	0.52	0.39
Net debt in the capital structure (2)	81.0%	83.5%	85.1%	85.3%	86.0%	87.0%	87.4%	87.0%
Average coupon on l-t debt	7.80%	8.10%	7.70%	8.50%	8.50%	9.40%	10.00%	10.10%
Common equity in capital structure	17.5%	16.5%	14.8%	14.7%	13.9%	13.0%	12.5%	12.9%
Common dividend payout (before extras.)	43.3%	62.9%	80.1%	83.2%	77.9%	76.7%	107.0%	128.9%
Coverage Ratios (3)								
EBIT interest coverage	2.40	1.91	1.64	1.65	1.47	1.18	1.21	1.19
EBITDA interest coverage	3.00	2.51	2.15	2.14	1.89	1.52	1.54	1.52
Fixed-charges coverage	2.40	1.91	1.64	1.65	1.47	1.18	1.21	1.19
Earnings Quality / Operating Efficiency								
Power purchases / revenues	56.9%	28.8%	23.6%	11.9%	8.4%	8.8%	8.9%	7.1%
Fuel costs / revenues	5.3%	1.6%	2.4%	0.6%	0.4%	2.3%	3.0%	2.2%
Operating margin	18.0%	32.3%	33.6%	40.1%	40.5%	39.1%	39.5%	39.5%
Net margin (before extras.)	10.9%	15.7%	13.4%	17.2%	14.8%	6.5%	8.0%	8.6%
Return on average equity (before extras.)	60.4%	40.4%	31.9%	36.0%	30.6%	13.4%	16.5%	16.2%
Profit returned to government (before extras.)	62.2%	79.7%	90.4%	91.8%	90.4%	93.7%	102.2%	109.5%
Approved ROE	16.59%	16.69%	17.47%	17.00%	14.81%	15.91%	12.74%	15.23%
Customers / employee	268	283	285	285	258	244	230	217
GWh sold / employee	12.1	12.5	11.8	10.5	9.4	7.8	7.5	6.9
Growth in customer base	1.0%	1.4%	1.5%	2.1%	2.0%	2.4%	3.0%	3.1%
Self-Generation - Cost Structure (4)	(cents per net generated kWh sold) (Tables may not add due to rounding)							
OM&A	1.62	0.99	0.95	0.86	0.89	1.02	1.05	1.11
Fuel	0.90	0.12	0.15	0.03	0.02	0.13	0.17	0.12
Variable costs	2.52	1.10	1.10	0.89	0.91	1.15	1.22	1.23
Government levies	0.92	0.93	0.94	0.95	0.95	0.99	1.00	0.98
Net interest expense	1.12	1.14	1.25	1.19	1.25	1.77	1.79	1.78
Total cash costs	4.56	3.18	3.29	3.04	3.11	3.91	4.01	3.98
Non cash financial charges	0.08	0.06	0.06	0.03	0.02	0.03	0.01	(0.06)
Depreciation	0.82	0.78	0.74	0.71	0.67	0.75	0.73	0.76
Total costs	5.46	4.02	4.09	3.78	3.80	4.69	4.75	4.68
Purchased power (cents per gross kWh purch.) (5)	16.44	4.30	3.76	3.26	3.41	3.43	2.75	2.80

(1) Capital expenditures are net of customer contributions.

R = Balance sheet restated to reflect gross debt and sinking fund assets.

(2) Columbia River Treaty and customer contributions excluded from capital structure.

(3) Before capitalized interest, AFUDC and debt amortizations.

(4) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

(5) Includes cost of power purchased for resale and related third-party transmission costs.

Income Statement ($ millions)	For years ended March 31 2001	2000	1999R	1998R	1997R	1996R	1995R	1994
Residential	892	894	855	839	866	822	792	762
Light industrial/commercial	866	849	838	828	809	790	774	751
Large industrial	524	482	488	424	471	492	466	475
Other energy sales	90	73	77	65	67	78	85	73
Subtotal - domestic	2,372	2,298	2,258	2,156	2,213	2,182	2,117	2,061
Trading revenues	5,458	1,129	739	341	164	51	142	95
Total energy revenues	7,830	3,427	2,997	2,497	2,377	2,233	2,259	2,156
Non-energy	59	53	46	57	49	61	40	42
Total revenues	7,889	3,480	3,043	2,554	2,426	2,294	2,299	2,198
Expenses:								
OM&A	755	475	443	411	439	423	421	438
Power purchase costs	4,371	893	614	188	113	114	124	105
IPP contract purchase costs	116	109	105	115	90	89	81	51
Fuel costs	420	56	72	16	9	52	70	48
Depreciation & amortization	380	375	347	342	327	312	292	300
Water rentals	255	276	267	280	296	239	231	217
Taxes	174	172	173	177	169	169	171	170
Total operating costs	6,471	2,356	2,021	1,529	1,443	1,398	1,390	1,329
Operating income	1,418	1,124	1,022	1,025	983	896	909	869
Interest expense	639	629	682	701	784	915	890	891
Non-cash financial charges	38	29	30	14	12	12	6	(25)
Other (income)/expense	(118)	(79)	(97)	(130)	(171)	(181)	(172)	(187)
Net interest expense	559	579	615	585	625	746	724	679
Income before extras.	859	545	407	440	358	150	185	190
Extraordinary items (1)	(413)	(129)	(12)	(32)	(19)	0	(23)	0
Net income	446	416	395	408	339	150	162	190
Operating Cash Flows	919	912	733	708	598	398	385	392
Less: payment to province	372	343	326	366	279	115	198	245
Less: capital exp. (net of contrib.)	331	354	346	278	272	314	361	373
Cash flows before working capital	216	215	61	64	47	(31)	(174)	(226)
Less: working capital	(659)	(118)	78	(43)	50	61	(91)	32
Free cash flow	875	333	(17)	107	(3)	(92)	(83)	(258)
Less: other investments	7	13	26	0	35	(63)	70	61
Plus: net financing funds	(216)	(365)	105	(227)	(98)	117	106	358
Net change in cash flows	652	(45)	62	(120)	(136)	88	(47)	39
Unit Revenues and Costs	(cents per kWh sold)							
Residential	6.14	6.12	6.11	6.12	6.11	6.12	6.11	6.12
Light industrial/commercial	5.32	5.32	5.31	5.34	5.32	5.33	5.32	5.33
Large industrial	3.36	3.29	3.32	3.25	3.32	3.38	3.37	3.35
Other energy sales	5.21	5.89	5.82	6.26	6.01	5.00	4.88	5.56
Domestic revenues	4.93	4.95	4.93	4.98	4.96	4.91	4.92	4.91
Electricity trade	22.84	4.82	3.95	2.59	1.67	2.10	3.62	3.59
Average electricity revenues	10.87	4.91	4.65	4.42	4.36	4.77	4.81	4.83
Ancillary revenues	0.08	0.08	0.07	0.10	0.09	0.13	0.09	0.09
Average revenues	10.95	4.98	4.72	4.52	4.45	4.90	4.89	4.92
Expenses:								
Operating & administration	1.05	0.68	0.69	0.73	0.81	0.90	0.90	0.98
Power purchases (incl. IPPs)	6.23	1.43	1.11	0.54	0.37	0.43	0.44	0.35
Natural gas	0.58	0.08	0.11	0.03	0.02	0.11	0.15	0.11
Variable costs	7.86	2.19	1.91	1.29	1.19	1.45	1.48	1.44
Government levies	0.60	0.64	0.68	0.81	0.85	0.87	0.86	0.87
Net interest expenses	0.72	0.79	0.91	1.01	1.13	1.57	1.53	1.58
Total cash costs	9.18	3.62	3.50	3.11	3.17	3.89	3.87	3.88
Cash margin	1.77	1.36	1.22	1.41	1.28	1.01	1.03	1.04
Non-cash financial charges	0.05	0.04	0.05	0.02	0.02	0.03	0.01	(0.06)
Depreciation	0.53	0.54	0.54	0.61	0.60	0.67	0.62	0.67
Pre-tax margin	1.19	0.78	0.63	0.78	0.66	0.32	0.39	0.43
Variable costs	7.86	2.19	1.91	1.29	1.19	1.45	1.48	1.44
Fixed costs (deprec, int + levies)	1.90	2.01	2.17	2.45	2.60	3.13	3.02	3.06
Total costs	9.76	4.20	4.09	3.74	3.80	4.58	4.50	4.50

(1) Transfer to Customer Profit Sharing $310 and transfer to Rate Stablization Account $103.

British Columbia Hydro & Power Authority

Operating Statistics (millions kWh)		For years ended March 31								
Electricity Sold - Breakdown		2001	2000	1999	1998	1997	1996	1995	1994	1993
Residential		14,537	14,599	13,987	13,701	14,167	13,442	12,957	12,442	12,600
Light industrial + commercial		16,292	15,960	15,776	15,511	15,201	14,823	14,542	14,086	14,070
Large industrial		15,573	14,644	14,705	13,042	14,175	14,569	13,812	14,178	13,785
Other		1,729	1,239	1,323	1,038	1,115	1,561	1,743	1,312	1,588
Total domestic electric		48,131	46,442	45,791	43,292	44,658	44,395	43,054	42,018	42,043
Trading volumes		23,900	23,410	18,715	13,168	9,826	2,427	3,927	2,645	5,643
Total sold		72,031	69,852	64,506	56,460	54,484	46,822	46,981	44,663	47,686
Energy sales growth		3.1%	8.3%	14.3%	3.6%	16.4%	-0.3%	5.2%	-6.3%	0.3%
Generation										
Hydro	90%	10,009	10,000	9,960	9,921	9,746	9,716	9,706	9,706	9,706
Gas	8%	912	912	912	912	912	912	912	912	912
Other thermal	2%	212	211	173	166	171	223	220	217	217
Installed capacity (MW)		11,133	11,123	11,045	10,999	10,829	10,851	10,838	10,835	10,835
Energy Generated (millions kWh)										
Hydro		45,447	49,927	47,399	50,334	53,334	41,695	39,921	40,101	49,211
Gas		3,975	1,312	3,177	1,378	428	3,502	3,812	3,248	1,766
Other thermal		518	407	101	67	66	65	65	62	77
Gross power generated	65%	49,940	51,646	50,677	51,779	53,828	45,262	43,798	43,411	51,054
Plus: purchases & exchange net	35%	27,291	23,299	19,100	9,296	5,950	5,921	7,450	5,567	566
Energy generated + purchased		77,231	74,945	69,777	61,075	59,778	51,183	51,248	48,978	51,620
Less: transmission losses + internal use		5,200	5,093	5,271	4,615	5,294	4,361	4,267	4,315	3,934
Total sold		72,031	69,852	64,506	56,460	54,484	46,822	46,981	44,663	47,686
Energy lost + used/Energy gen + purch		6.7%	6.8%	7.6%	7.6%	8.9%	8.5%	8.3%	8.8%	7.6%
Maximum primary peak demand (MW)		8,995	8,423	8,777	8,243	8,267	8,451	8,168	8,059	8,156
Demand/Installed capacity (MW)		80.8%	75.7%	79.5%	74.9%	76.3%	77.9%	75.4%	74.4%	75.3%
Export Interconnections										
Alberta		600	600	600	600	600	600	600	600	600
U.S.		3,150	3,150	3,150	3,150	2,300	2,300	2,300	2,300	2,300
Total (MW)		3,750	3,750	3,750	3,750	2,900	2,900	2,900	2,900	2,900
Interconnections as a % of Installed Capacity		33.7%	33.7%	34.0%	34.1%	26.8%	26.7%	26.8%	26.8%	26.8%

Brilliant Power Funding Corporation

Current Report: August 31, 2001
Previous Report: November 13, 2000

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RATING

Rating	*Trend*	*Rating Action*	*Debt Rated*
A (high)	Stable	Upgraded	Series A Project Bonds
A (high)	Stable	New Rating	Series B Project Bonds

RATING HISTORY

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

RATING UPDATE

DBRS is upgrading the rating of Brilliant Power Funding Corporation ("BPFC") to A (high) from A, with a Stable trend. The rating is being upgraded based on the improving 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 and the rating increase reflects the increasing discrepancy between its cost of production and the market value of the power produced. This reduces the concern associated with the fact that West Kootenay Power Limited (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 increasing importance of Powerex (the non-guaranteed export subsidiary of British Columbia Hydro and Power Authority 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 will positively affect the credit quality of BPFC notwithstanding the issuance of additional debt (Series B Bonds) that ranks pari passu with the Series A Bonds.

The main challenge BPFC must contend with is the lack of control over the credit strength of its only customer, West Kootenay Power Limited. Consolidated leverage is relatively high and coverage ratios are weak compared to other electric utilities, but are consistent with the narrow operating focus of the company.

RATING CONSIDERATIONS

Strengths:

- Low-cost electricity generation
- Long-term "take-or-pay" contract with West Kootenay Power
- Back-up sales agreement with B.C. 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 (rated AA (low))

Challenges:

- Highly dependent on the credit worthiness of its only customer, West Kootenay Power, and B.C. Hydro
- High leverage and relatively weak coverage ratios compared to other electric utilities

FINANCIAL INFORMATION

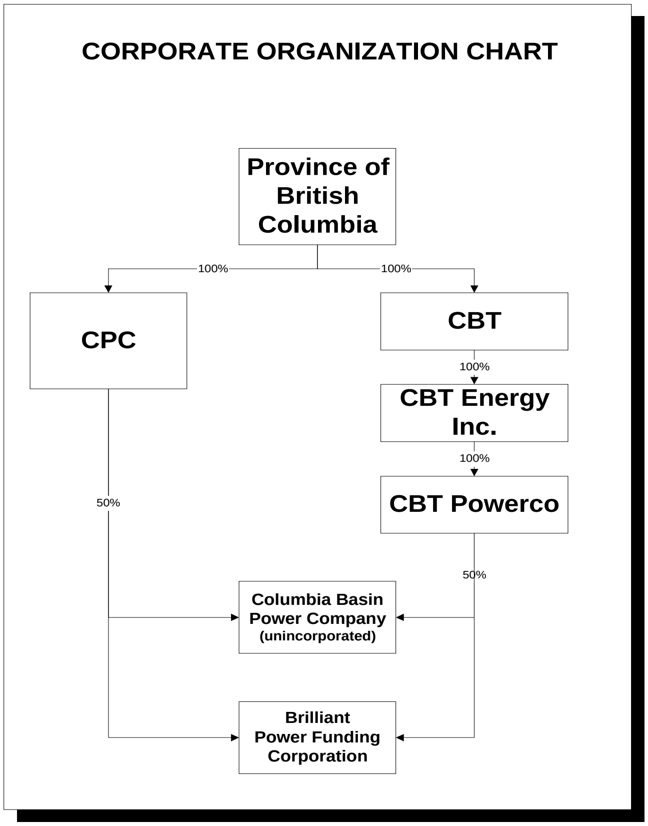
	12 mos. ended	For years ended March 31				
(Columbia Basin Power Company)	June 2001	2001	2000	1999	1998	1997 (1)
Debt service coverage (times)	1.56	1.53	1.43	1.40	1.35	1.37
EBIT interest coverage (times)	1.42	1.41	1.29	1.25	1.19	1.18
Cash flow-divid./capital expenditures (times)	0.19	0.13	0.36	0.35	0.35	0.76
% debt in capital structure	69.6%	70.1%	69.9%	69.0%	68.1%	67.5%
Operating income ($ millions)	12.3	12.0	10.8	10.4	9.9	8.5
Net income ($ millions)	3.9	3.7	2.5	2.2	1.6	1.3
Operating cash flow ($ millions)	6.7	6.3	4.9	4.5	3.9	3.2
Unit revenues (cents per kWh sold)	2.62	2.79	2.52	2.38	2.48	2.28
Total costs (cents per kWh sold)	2.16	2.32	2.22	2.12	2.28	2.10
Pre-tax margin (cents per kWh sold)	0.46	0.47	0.30	0.26	0.20	0.18

(1) 11-month period since inception.

Note that, 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 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 West Kootenay Power Ltd.

Corporate Profile



The Province of British Columbia established the Columbia Power Corporation ("CPC") and the Columbia Basin Trust ("CBT") with a mandate to invest provincial funds in power projects in the Columbia-Kootenay region of British Columbia.

Brilliant Power Funding Corporation ("BPFC") was established in 1996 to hold legal title to the real and tangible property comprising the Brilliant Dam (located in the southern interior of B.C.) and to issue Brilliant Project Bonds, in both cases as agent and nominee for CPC and CBT Power Corp.

Columbia Basin Power Company ("CBPC"), an unincorporated joint venture equally owned by CPC and CBT Power Corp., has been assigned the rights to the use of the hydroelectric assets. CBPC operates the Brilliant Dam assets and is committed to maintaining the assets. All power is sold to West Kootenay Power.

Rating Considerations

Strengths: (1) Brilliant Dam is a low-cost generator of electricity with total generating costs of 2.32 cents/kWh sold versus about 5.4 cents/kWh at both West Kootenay Power and B.C. Hydro. This competitive cost advantage is a fundamental strength of the power purchase agreement and provides comfort in the event power is sold into the open market (should both West Kootenay Power and Powerex default) and/or industry deregulation introduces competition in the province.

(2) Operation of the Brilliant Dam is supported by a 60-year power purchase agreement with West Kootenay Power, a regulated utility. Volume or demand risk is eliminated since all power is sold to West Kootenay Power during the first 30 years under a "take-or-pay" contract, which provides stable cash flows. Brilliant Dam is an important power supply source to West Kootenay Power, who currently must purchase about 50% of its power. Rates are set to recover operating and financing costs, capital expenditures, and a 12.5% return on invested equity. After the remaining 25 years (beginning in 2026), rates will be subject to annual market-based price adjustments. Power purchases related to the upgrades are on basically the same terms except at a higher price.

(3) Operations are further supported by a back-up power purchase agreement (30-year term) with B.C. Hydro's export subsidiary, Powerex, in the event West Kootenay Power defaults. The contract covers all debt service costs. While Powerex obligations are not guaranteed by B.C. Hydro, there is implied support given the interlocking Board structure and the growing importance of export markets to B.C. Hydro.

(4) The financing structure is adequate and includes credit enhancements: (a) a six-month debt service reserve fund designed to cover any transition period between a West Kootenay Power default and start of the back-stop agreement; and (b) an operating reserve fund equal to one-quarter of annual operating expenses to cover any potential future cash flow deficiencies.

(5) Both joint venture partners (CPC and CBT Power Corp.) are owned by the Province, which suggests implied support despite the lack of a government guarantee. The joint venture is exempt from paying income taxes, which contributes to its low-cost structure. The Province has committed $500 million to CPC and CBT Power Corp. over ten years to year 2005 ($300 million advanced to date) that provides a high level of financial viability. Such funding is not available to support operations, but can be used to finance capital improvements.

(6) CBPC's earnings do not fluctuate with water flows, unlike other hydro-based utilities. Therefore, earnings are relatively stable. Under the terms of the Canal Plant Agreement with B.C. Hydro, BPFC receives a fixed energy entitlement regardless of water levels. Also earnings do not fluctuate due to changes in generation as a result of forced or scheduled maintenance outages.

Challenges: (1) Given that BPFC has only one customer, West Kootenay Power, its credit rating is highly dependent on the creditworthiness of its only customer (West

Kootenay Power is currently rated BBB (high)/with a Stable trend – see separate report). BPFC's credit rating is also influenced by that of B.C. Hydro (rated AA (low)/with a Stable trend) due to the back-up sales agreement with Powerex. These important credit considerations are beyond BPFC's control. A decline in the ratings of West Kootenay Power and/or B.C. Hydro could impact BPFC's rating.

(2) Coverage ratios are relatively weak in comparison to other investor-owned electric utilities rated by DBRS. The risk to bondholders is offset by the requirement for a minimum debt service coverage ratio of 1.3 times, and the fact that earnings are relatively stable.
(3) Amortization of the Series A and B bonds is long-term in nature (25 years to May 2026), and the Brilliant Dam is a small, single asset facility.

EARNINGS

Brilliant Power Funding Corporation
(Columbia Basin Power Company)

Income Statement	12 mos. ended	3 mos. ended		For years ended March 31				
($ millions)	June 2001	June 2001	June 2000	2001	2000	1999	1998	1997 (1)
Revenues	22.493	5.639	5.269	22.123	21.329	20.210	20.301	16.764
Expenses:								
OM&A	1.432	0.237	0.354	1.549	1.790	1.492	1.747	1.562
Property + capital taxes	2.214	0.581	0.526	2.159	2.327	2.070	2.108	1.683
Water rentals	3.775	0.907	0.992	3.859	3.963	3.922	4.211	3.189
Amortization	2.741	0.805	0.621	2.556	2.414	2.314	2.297	1.832
Total operating costs	10.162	2.531	2.492	10.123	10.495	9.798	10.363	8.266
Operating income	12.331	3.108	2.777	11.999	10.834	10.412	9.938	8.497
Interest expense	9.227	2.280	2.195	9.143	8.716	8.601	8.524	7.361
Amort. of debt service costs	0.036	0.009	0.009	0.036	0.036	0.036	0.036	0.030
Other (income)/expense	(0.814)	(0.089)	(0.135)	(0.860)	(0.410)	(0.380)	(0.237)	(0.219)
Net interest costs	8.450	2.200	2.069	8.319	8.343	8.257	8.324	7.172
Pre-tax income	3.881	0.909	0.708	3.680	2.492	2.155	1.614	1.325
Income taxes	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Net income	3.881	0.909	0.708	3.680	2.492	2.155	1.614	1.325
Millions of kWh sold	859.994	245.025	178.301	793.270	845.323	847.997	817.292	733.740

(1) 11-month period.

Net income for the fiscal year ended March 31, 2001, rose 47.7% to $3.7 million over the prior year. This earnings growth was primarily attributable to: (1) the escalation of payments received for power sold under the Brilliant Power Purchase Agreement (with West Kootenay Power) despite the decline in the amount of power sold due to the four-month withdrawal from service of generating unit #2 to allow for upgrade and life extension work; and (2) the commencement of increased power production resulting from the turbine upgrades. Interest earnings were also up significantly in 2000-01. However, the increase was offset by an almost equivalent increase in gross interest costs. Earnings continued to rise during the first quarter of the 2001-02 fiscal year in line with the continued escalation of revenues received under the payment formulas and due to increased power sales as a result of completion of the upgrade work on unit #2.
The Brilliant Dam fixed energy entitlement ensures that rainfall does not impact CBPC's earnings. In addition, revenues are not negatively affected by changes in generation due to plant outages as evidenced by the results for 2000-01.

Outlook: The primary driver of future earnings growth will be the planned plant upgrades and related life extension work as rates charged allow full recovery of sustaining capital/upgrade capital expenditures plus a return on invested equity component fixed at 12.5%. Management projects that income will more than double over the next three years. Earnings growth is expected to be more modest once this major capital program is complete. The upgrades, which include installing four new, more efficient turbines, will add about 20 MW to the existing 125 MW of installed capacity. The first upgrade was completed last summer (August 2000). Work on the second upgrade began in late August 2001 (delayed from the original plan due to a strike by the employees of west Kootenay Power, the manager of the dam), and completion of all four upgrades is currently expected by December 2002.
The proceeds from the Series B bonds are being used to repay loans made to the Joint Venture by CPC with respect to upgrades and the sustaining capital program and to fund the appropriate reserve fund requirements.

FINANCIAL PROFILE

	12 mos. ended	3 mos. ended		For years ended March 31				
	June 2001	June 2001	June 2000	2001	2000	1999	1998	1997 (1)
Operating cash flow	6.658	1.723	1.337	6.273	4.942	4.505	3.947	3.187
Less: distributions to venturers	3.500	0.000	0.000	3.500	3.450	2.850	2.660	1.480
capital expenditures	16.784	2.202	7.333	21.915	4.116	4.728	3.730	2.247
Cash flow before working capital	(13.626)	(0.479)	(5.996)	(19.142)	(2.624)	(3.073)	(2.443)	(0.540)
Less: changes in working capital	6.119	(0.625)	(5.628)	1.117	(0.829)	1.298	(1.493)	1.222
Free cash flow	(19.745)	0.146	(0.368)	(20.259)	(1.795)	(4.371)	(0.950)	(1.762)
Less: other investments	0.617	0.000	0.000	0.617	0.395	0.606	0.403	138.937
Plus: net financing (before dividends)	2.072	(0.483)	16.324	18.880	4.565	5.430	1.664	141.003
Net change in cash	(18.290)	(0.337)	15.957	(1.996)	2.374	0.453	0.311	0.304
Debt service coverage (times)	1.56	1.44	1.33	1.53	1.43	1.40	1.35	1.37
EBIT interest coverage (times)	1.42	1.40	1.33	1.41	1.29	1.25	1.19	1.18
Cash flow / total debt (times)	0.06	-	-	0.05	0.05	0.04	0.04	0.03
Cash flow / capital expenditures (times)	0.40	0.78	0.18	0.29	1.20	0.95	1.06	1.42
% debt in the capital structure	69.6%	69.6%	70.0%	70.1%	69.9%	69.0%	68.1%	67.5%

(1) 11-month period.

Balance sheet leverage has remained relatively stable over the past three years at about 70% debt to total capital. The debt service coverage ratio has improved fairly consistently over the past three years and stood at 1.56 times at June 30, 2001.

Capital expenditures in 2000-01 were $21.9 million, up sharply from the previous four years. The significant increase reflects the start of the life extension/upgrade program for the turbines, as well as the start and completion of other major sustaining capital projects including the construction of a new switchyard and Phase I of the dam stabilization project. The projects were funded with a 70/30 debt/equity mix. The costs of both asset maintenance (i.e., life extension) and capital upgrades are recovered through specific charges (sustaining capital charge and upgrade capital charge) that are incorporated in the pricing structure of the power sales contract.

Outlook: Capital expenditures are estimated to total $49 million over the next three years, a sharp increase from historical annual levels. The planned capital budget for 2001-02 is $39 million (of which $28 million is related to sustaining capital expenditures, including life extensions and $11 million is related to upgrades). Given that the capital upgrade program is expected to be financed with a 70/30 mix of debt and equity, leverage will remain high.

While relatively weak compared to investor-owned electric utilities, the EBIT interest coverage ratio should remain fairly stable. Furthermore, debt service obligations are supported by the nature of the power sales contracts, which at a minimum covers all debt service costs.

Covenant restrictions limit the issuance of additional bonds, unless the minimum debt service coverage ratio exceeds 1.3 times. Including the debt service related to the Series B project bonds recently issued and the additional debt issuance required to finance all of the planned capital expenditures, management projects that the debt service ratio will decline this fiscal year to just under 1.5 times, but will gradually and consistently improve over the medium term to about 1.6 times by 2007-08.

OPERATING LINES OF CREDIT

A $10 million secured, operating line of credit ranks equally with the Series A and B Project Bonds.

DEBT SERVICE SCHEDULE

	2002	2003	2004	2005	2006
Series A Project Bonds ($millions)	9.27	9.27	9.27	9.27	9.27
Series B Project Bonds ($millions)	2.38	2.38	2.38	2.38	2.38

The payments include both principal and interest payments.

Brilliant Power Funding Corporation

(Columbia Basin Power Company)

Balance Sheet ($ millions)	As at March 31 2001	2000	1999		As at March 31 2001	2000	1999
Assets				**Liabilities & Equity**			
Cash	1.4	3.4	1.1	Short-term debt	1.0	0.9	0.9
AR + unbilled revs.	6.4	5.5	5.3	A/P + accrueds	6.1	6.4	5.3
Prepaids	1.0	1.0	1.0	Current liabilities	7.1	7.3	6.2
Current assets	8.8	10.0	7.4	Project bonds	91.6	92.6	93.5
Net fixed assets	159.6	140.3	138.6	Advances	26.6	12.0	7.2
Debt service fund	4.6	4.6	4.6	Equity-CPC	25.4	22.7	22.9
Operating reserve account	2.0	1.4	1.0	-CBT Power	25.4	22.7	22.9
Deferred costs	0.9	0.9	1.0				
Total	176.0	157.3	152.6	Total	176.0	157.3	152.6

Ratio Analysis *	12 mos. ended June 2001	For years ended March 31 2001	2000	1999	1998	1997 (1)
Debt service coverage (times)	1.56	1.53	1.43	1.40	1.35	1.37
EBIT interest coverage (times)	1.42	1.41	1.29	1.25	1.19	1.18
Cash flow / total debt (times)	0.06	0.05	0.05	0.04	0.04	0.03
Cash flow / capital exp. (times)	0.40	0.29	1.20	0.95	1.06	1.42
Cash flow-divid / capital exp. (times)	0.19	0.13	0.36	0.35	0.35	0.76
% debt in the capital structure	69.6%	70.1%	69.9%	69.0%	68.1%	67.5%
Common equity in the capital structure	30.4%	29.9%	30.1%	31.0%	31.9%	32.5%
Dividend payout ratio	90.2%	95.1%	138.5%	132.3%	164.8%	111.7%
Operating margin	54.8%	54.2%	50.8%	51.5%	49.0%	50.7%
Net margin	17.3%	16.6%	11.7%	10.7%	7.9%	7.9%
Return on avg. partners equity	7.6%	7.6%	5.5%	4.7%	3.5%	2.9%
Unit revenues (cents per kWh sold)	2.62	2.79	2.52	2.38	2.48	2.28
Variable costs (cents per kWh sold)	0.17	0.20	0.21	0.18	0.21	0.21
Fixed costs (cents per kWh sold)	1.99	2.13	2.01	1.95	2.07	1.89
Total costs (cents per kWh sold)	2.16	2.32	2.22	2.12	2.28	2.10
Net margin (cents per kWh sold)	0.46	0.47	0.30	0.26	0.20	0.18
Installed capacity - MW	130	130	125	125	125	125

(1) 11-month period since inception.

* Note that, due to the structured nature of debt instruments, the above ratios are not directly comparable to Canadian utilities.

Canadian Utilities Limited

Current Report: August 15, 2001
Previous Report: October 20, 2000

RATING

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Rating	*Trend*	*Rating Action*	*Debt Rated*
"A"	Stable	Confirmed	Corporate Debt*
Pfd-2 (high)	Stable	Confirmed	Preferred Shares**

RATING HISTORY	*Current*	*2000*	*1999*	*1998*	*1997*	*1996*
Corporate Debt*	"A"	"A"	A (high)	NR	NR	NR
Preferred Shares**	Pfd-2 (high)	Pfd-2 (high)	Pfd-1 (low)	NR	NR	NR

*Highest rating applicable to the direct public obligations of Canadian Utilities Limited.
** The preferred shares, which will continue to be held by Canadian Utilities Limited, are direct obligations of the regulated operating subsidiaries of CU Inc. Any new preferred shares will be rated Pfd-2.

RATING UPDATE

The ratings on Canadian Utilities Limited's ("CUL" or "the Company") corporate debt and preferred shares are confirmed at "A" and Pfd-2 (high), respectively, both with Stable trends based on the following factors. Despite the unfavourable regulatory decisions delivered in 2000 for the Company's gas utilities, the strong results by the power generation segment (largely due to higher power prices) resulted in continued growth in CUL's net earnings and operating cash flows. However, in line with the recent trend, CUL had a free cash flow deficit due to higher capital expenditures, thus requiring external financing. Despite higher debt levels, key leverage and coverage ratios remained reasonable in 2000. Results for the first half of 2001 suggest a continuation of the strong financial results recorded in the past as earnings growth in the power generation segment more than offset the weaker results by the regulated gas utility (due to warmer-than-normal temperatures).

CUL's regulated utilities, its diversified energy portfolio and increased geographic diversification should continue to provide relative stability to the Company's financial profile. The favourable market conditions in Alberta, the good economic outlook for the Company's primary franchise area and the growing importance of higher return, non-regulated businesses (primarily power generation) should contribute to continued good operating and financial results. However, the growing importance of non-regulated activities will also increase the Company's risk profile, as non-regulated activities tend to be more volatile than regulated activities. CUL must also continue to face the challenge of dealing with the cumbersome regulatory environment in Alberta.

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
- Increased business risk from power purchase agreements
- Cumbersome regulatory environment in Alberta

FINANCIAL INFORMATION

		12 months ended	For the year ended December 31				
Consolidated basis		June 2001	2000	1999	1998	1997	1996
Fixed-charges coverage (times)		2.60	2.60	2.54	2.44	2.36	2.23
Cash flow/total debt (times) (incl debt equiv)		0.20	0.19	0.20	0.18	0.18	0.18
Cash flow/capital expenditures (times)		1.07	1.21	1.51	1.14	1.27	1.73
% gross debt in capital structure (incl debt equiv)		57.4%	58.6%	57.7%	59.3%	60.0%	60.2%
Operating income ($ millions)		600.9	594.2	550.0	549.1	525.9	541.3
Segmented income* - utilities (gas & electric)	32%	73.6	77.2	92.4	155.2	151.5	144.8
- power generation	47%	108.7	96.5	67.2	26.1	20.9	16.7
- other businesses	21%	49.6	53.1	44.1	14.2	12.2	14.8
- corporate/eliminations	0%	0.9	0.6	(3.6)	(5.3)	(3.1)	(5.0)
Net income ($ millions, after pfd)		232.8	227.4	200.1	190.2	181.5	171.3
Operating cash flow ($ millions)		518.5	490.0	465.1	425.7	401.6	383.0
Ttoal electricity sales (GWh)		14,603	14,053	13,765	12,658	12,437	12,082
Gas volume throughputs (bcf)		944.9	928.1	828.8	771.5	669.2	656.8

* 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 (held by CU Inc.) primarily based in Alberta, in addition to non-regulated utility subsidiaries and holdings in England, Australia and Canada. ATCO Ltd. owns 52% of Canadian Utilities Limited.

COMPANY PROFILE

Canadian Utilities Limited is a holding company whose principal operating subsidiaries are involved in both regulated and non-regulated gas and electricity utility businesses. The Company's primary operating businesses consist of the following.

CU Inc. is a holding company with regulated gas (ATCO Gas and ATCO Pipelines) and electric (ATCO Electric) utility operations, as well as electric generation assets that were previously regulated, but now operate under power purchase agreements (PPAs) (Alberta Power (2000) Ltd.). The PPAs provide relative earnings and cash flow stability, similar to the other regulated businesses. ATCO Electric's business franchise covers most of northern Alberta (north of Edmonton and parts of central Alberta) as well as regions in the Yukon and the Northwest Territories. ATCO Gas' franchise covers most of Alberta. CUL's regulated businesses currently comprise about 65% of the Company's net earnings, providing an important degree of stability to its financial position.

ATCO Power Ltd. is involved in the development, construction, operation and management of independent power projects (IPPs) in Canada (Alberta and B.C.), the U.K. and Australia. It also owns an important portion of these generation assets – 725 MW out of the total capacity of 1,997 MW. Two of the generation plants – Joffre, Alberta and Barking, U.K. – comprise the majority (61%) of ATCO Power's current IPP capacity. ATCO Power has five IPPs currently under construction (CUL's share at 524 MW) in Alberta and Saskatchewan. ATCO Power is an important contributor to CUL's earnings, currently at about 23% of consolidated net income.

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

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

Other Businesses (non-regulated) consist of: (1) administrative services for gas and electric utilities, marketers and municipalities (ATCO I-Tek and ATCO Singlepoint); and (2) sale of fly ash and other combustion by-products produced in coal-based generation (Ashcor) and 50% interest in a wood preservation products manufacturer (Genics Inc.)

Business Segments

REGULATED – 65% OF NET EARNINGS

ATCO Electric, ATCO Gas, ATCO Pipelines

Strengths:

- Regulated businesses provide relative financial stability
- Operating cash flows consistently in excess of capital expenditure requirements
- Attractive fundamentals of gas contributes to positive earnings growth outlook
- Strong provincial economy fueling growth of customer base

Challenges:

- Cumbersome regulatory environment with significant regulatory lag
- Earnings sensitive to economic cycle (industrial-oriented customers account for 75% of volumes) and somewhat sensitive to weather (25% of volumes)
- Earnings sensitive to interest rates via approved ROEs, which have been falling

Effective January 1, 2001, CU Inc. merged and restructured its two gas subsidiaries (formerly Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited) into two separate divisions of ATCO Gas and Pipelines Ltd.: (1) ATCO Pipelines, a transmission operation, which essentially provides gas transportation services; and (2) ATCO Gas, a distribution operation, which supplies and distributes gas. For regulatory purposes, however, separate accounts must be maintained for four new divisions (ATCO Gas North, ATCO Pipelines North, ATCO Gas South and ATCO Pipelines South) until December 31, 2004.

ATCO Electric (transmission and distribution), ATCO Gas (distribution) and ATCO Pipelines (transmission) are regulated on a cost-of-service/rate-of-return methodology with deferral accounts that provide for a flow-through of gas costs (for the gas utility) and electricity costs (for the electric utility).

ATCO Electric is currently operating under a negotiated settlement. In 1998, the AEUB approved a five-year (1998-2002) negotiated settlement for ATCO Gas North and ATCO Pipelines North, which is cost-of-service based and includes an incentive methodology. A final regulatory decision in 2000 set ATCO Gas South and ATCO Pipelines South's 1997 and 1998 common equity component at 37% and their approved ROEs at 10.50% for 1997 and 9.375% for 1998. In December 2000, the AEUB set the approved ROEs for ATCO Gas South and ATCO Pipeline South at 9.375% for both 1999 and 2000. For 2001 and 2002, ATCO Gas South has applied for an approved ROE of 11.50%, while ATCO Pipelines South has applied for an approved ROE of 12.00%. A decision has not yet been rendered by the AEUB for 2001 and 2002.

Alberta Power (2000)

Strengths:
- PPAs enable recovery of costs (variable and fixed), incorporate 450 bp risk premium above long-term Canada bonds, deemed equity component raised to 45%

Challenges:
- PPAs increase business risk

Generation assets under PPAs – Alberta Power

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

The PPAs allow for the recovery of fixed and variable costs plus a profit. The risk premium is materially higher than what other regulated Canadian utilities are allowed, amounting to 450 basis points over long-term Canada bonds on a 45% deemed equity, reflecting the greater business risk. The increased business risks facing CUL under the PPAs are as follows. (1) CUL is obligated to meet specified output commitments. Generators will be penalized (required to make a payment to the PPA holder) if actual output is below the specified capability of the respective unit. However, if generators exceed these thresholds, they are entitled to an incentive payment. (2) Forecast capital expenditures for the next 20 years under the PPAs may be below actual requirements. The variance is not recoverable. (3) Establishing who is at fault and defining "force majeure" in the event of an unplanned shutdown may be difficult, as evidenced by the most recent case with TransAlta, and could lead to disputes and litigation.

NON-REGULATED – 35% OF NET EARNINGS

Strengths:
- Non-regulated generation assets offer greater earnings growth potential
- Deregulation, tight supply-demand market conditions in Alberta creating opportunities for growth
- Long-term sales contracts/fuel cost flow-throughs minimize merchant power risks
- Geographic and fuel source diversification

Challenges:
- Non-regulated generation assets more highly leveraged than regulated assets and subject to increased competitive pressures
- New business risks (currency, counterparty) increase overall risk profile
- Potential construction cost overruns

ATCO Power

Independent Power Projects	Total capacity (MW)	ATCO's share (MW)
Operating		
McMahon, B.C.	120	60
Primrose, Alberta	85	42*
Poplar Hill, Alberta	43	43*
Rainbow Lake, Alberta	43	22*
Joffre, Alberta	480	190*
Barking, U.K.	1,000	255
Heathrow Airport, U.K.	14	7
Osborne, Australia	180	90
Bulwer Island, Australia	32	16
Total	**1,997**	**725**
Under Construction		
Muskeg River, Alberta	170	119*
Scotford, Alberta	150	150*
Cory, Saskatchewan	260	130*
Valleyview, Alberta	92	92*
Oldman River, Alberta	33	33*
Total	**705**	**524**

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

Independent power projects are currently more highly leveraged than generation assets under the PPAs and regulated utility businesses. However, most of the projects to date have been financed on a non-recourse basis, with CUL's exposure limited to the Company's equity investment. Much of the Company's future growth will come from this business segment. The Company has an effective 725 MW of non-regulated power projects and a further 524 MW under construction. This business unit has the potential to alter the Company's overall risk profile, by increasing CUL's exposure to currency, counterparty and merchant power risks. However, some of the risk will be mitigated by the fact that about 60% of the new power will be subject to long-term sales contracts, including fuel supply contracts. Furthermore, given the tight supply-demand market conditions in Alberta and Saskatchewan, those plants without long-term sales contracts are not likely to be subject to undue competitive pressures over the next two to three years.

All of the power projects currently under construction are scheduled for commissioning in 2002 and 2003.

ATCO Midstream, ATCO Frontec, ATCO Singlepoint and other non-regulated businesses

ATCO Midstream recently completed the acquisition of Wolcott Gas Processing Ltd., which should add incrementally to the segment's earnings. A significant component of ATCO Frontec's earnings is generated from low-risk service contracts, usually awarded in a bidding process. Activities include the operation and maintenance of the Alaska Radar System, and the provision of various services for the Department of National Defence's five peacekeeping installations in Bosnia-Herzegovina.

EARNINGS

	12 months ended	6 months ended		For years ended December 31			
($ millions)	Jun. 2001	Jun. 2001	Jun. 2000	2000	1999	1998R	1997
Revenues	3,917.0	2,288.5	1,294.6	2,923.1	2,207.7	1,951.8	1,927.6
EBITDA	842.9	424.5	414.5	832.9	779.5	757.0	718.6
EBIT	600.9	304.1	297.4	594.2	550.0	549.1	525.9
Net interest expense	167.3	80.7	83.4	170.0	156.3	150.0	145.3
Net income before extraordinary items & pfd divd.	249.8	132.7	127.7	244.8	221.6	218.6	212.5
Net income available to common	232.8	124.2	118.8	227.4	200.1	190.2	181.5

Segmented Earnings	12 months ended	6 months ended		For years ended December 31			
($ millions)	Jun. 2001	Jun. 2001	Jun. 2000	2000	1999	1998R	1997
Regulated (1)	141.8	74.6	85.9	153.1	156.0	155.3	151.6
Non-regulated	91.0	49.6	32.9	74.3	44.1	34.9	29.9
Consolidated net income (after pfd)	232.8	124.2	118.8	227.4	200.1	190.2	181.5
Regulated electricity sales (GWh)	10,243	5,108	5,257	10,392	10,068	10,188	10,089
IPP electricity sales (GWh)	4,360	2,249	1,550	3,661	3,697	2,470	2,348
Gas volume throughputs (Bcf)	944.9	492.7	476.0	928.1	828.8	771.5	669.2

(1) Includes generation assets under PPAs

Higher power prices in 2000 were the primary driving force behind the 13.6% increase in CUL's consolidated net income in 2000 to $227.4 million. Growth in CUL's earnings was also supported by the contribution of two new plants that became operational in 2000: the Joffre, Alberta plant (ATCO Power's share is 190 MW) became operational in June 2000; and the Bulwer Island, Australia (ATCO Power's share is 11 MW) came on line in October 2000. Other non-regulated businesses (primarily ATCO Midstream) contributed to the growth in earnings as well, helping to offset the significant $15.2 million decline in the net income of the regulated electric and gas utility businesses. The earnings of the gas utility business was adversely affected by unfavourable regulatory decisions delivered in 2000 for the years 1997 to 2000 for one of the gas subsidiaries.

Outlook: Continued strong growth in power generation was the primary driver behind the 3.9% increase in consolidated earnings (before preferred dividends) for the six months ended June 30, 2001, relative to the same period in 2000. The regulated utilities segment experienced a further decline in earnings during the first half of 2001 due to 6.7% warmer-than-normal temperatures. The results for the first half of 2001 suggest the Company should report good results for the year as a whole.

Non-regulated generation is expected to be the primary contributor to earnings growth over the medium term. The Company currently has five independent power projects under construction, with all of them projected to be operational in 2002 and 2003. These power projects should provide a significant boost to CUL's operating income and earnings. However, they will also increase the Company's risk profile. The Company also has a number of other projects under development, which should also contribute to earnings growth when they become operational. To date, competitive pressures have not been a concern because of the tight supply-demand conditions in Alberta. However, as more supply comes on line, the Company will face increased competition, which could negatively impact earnings.

The Company's regulated utility businesses (ATCO Gas, ATCO Electric and ATCO Pipelines) will continue to provide relative stability to CUL's earnings and cash flows. In the absence of further unfavourable regulatory decisions, these operations should continue to grow in line with Alberta's economic growth and will continue to be influenced by volatility in the weather. The earnings contribution from Alberta Power (the generation assets subject to the PPAs) is projected to decline over time as the assets near the end of their contracted lives.

CUL's remaining businesses (primarily, ATCO Midstream, ATCO Frontec and ATCO Singlepoint) should continue to provide incremental returns, although these businesses are involved in highly competitive activities, especially ATCO Midstream. While these businesses will increase the Company's risk profile as they continue to grow, they currently make up a relatively small proportion of CUL's net income and therefore, have not yet had significant impact on its financial profile.

Financial Profile & Sensitivity Analysis

FINANCIAL PROFILE

CUL's financial profile remained strong in 2000 and the first six months of 2001 indicate no change in the situation, although its risk profile is beginning to increase as the Company's non-regulated businesses grow in importance. In line with the recent trend, the Company had a gross free cash flow deficit in 2000 due to higher capital expenditures. Over the past five years, CUL's consolidated gross free cash flow has generally been positive, although some deficits have been recorded but they have tended to be relatively small (under $50 million).

CUL's consolidated net debt as a share of capital (DBRS-adjusted) has remained relatively stable over the last three years at just under 60%, but has come down by more than five percentage points since the mid-1990s. Net debt in the capital structure edged higher in 2000 largely a result of increased short-term debt due to CU Inc.'s increased working capital requirements related to higher gas costs. However, short-term debt fell significantly during the first half of 2001, in line with reduced working capital requirements as the higher gas costs were recovered, bringing the debt/capital ratio down to 57.4%.

Outlook: Although operating cash flows are expected to remain strong, external financing requirements over the next few years will likely increase given there are five IPPs currently under construction. CUL's total annual capital expenditures are expected to remain in the $450 million - $550 million range for the next two years. IPPs have historically been financed with non-recourse bank debt and generally secured by project assets. The Company has not directly issued any long-term debt securities in the public debt markets since the mid-1999 reorganization when all debt obligations associated with the regulated utilities were transferred to CU Inc.

Consolidated leverage is expected to increase over time as the generation assets become a larger component of total assets and given that the IPPs tend to be project financed and more highly leveraged (typically on 70%-30% debt-to-equity basis) than regulated businesses. EBIT interest coverage has been above 3.0 times since 1996, but dipped just below 3.0 times during the first half of 2001. Interest coverage could come under pressure as consolidated leverage increases.

	Actual							
	12 mos. ended	For years ending Dec. 31				**Stress testing**		
Consolidated Cash Flow Statement	June 2001	1997	1998R	1999	2000	Year 1	Year 2	Year 3
Net income (after pfd)	232.8	181.5	190.2	200.1	227.4	167.6	155.3	143.4
Depreciation	242.0	192.7	207.9	229.5	238.7	259.0	270.3	281.0
Other non-cash adjustments	43.7	27.4	27.6	35.5	23.9	30.0	30.0	30.0
Operating cash flow	518.5	401.6	425.7	465.1	490.0	456.6	455.6	454.3
Less: common dividends	116.5	99.5	103.9	109.0	114.0	115.0	115.0	115.0
capital expenditures (net of contrib)	485.7	317.0	372.6	308.9	405.8	450.0	450.0	450.0
Gross free cash flow	(83.7)	(14.9)	(50.8)	47.2	(29.8)	(108.4)	(109.4)	(110.7)
Less: working capital changes	(182.6)	20.1	72.0	38.4	139.9	0.0	0.0	0.0
Free cash flow	98.9	(35.0)	(122.8)	8.8	(169.7)	(108.4)	(109.4)	(110.7)
Less: other investments	38.7	1.4	(5.2)	42.2	26.3	0.0	0.0	0.0
Plus: net debt	219.7	57.8	231.9	137.5	253.6	108.4	109.4	110.7
Plus: net preferreds	0.0	0.5	(68.1)	(96.3)	(34.1)	0.0	0.0	0.0
Plus: net common equity	0.6	(24.1)	0.6	(0.6)	(1.7)	0.0	0.0	0.0
Plus: other financing	(40.3)	12.0	(46.4)	(5.9)	(31.2)	0.0	0.0	0.0
Net change in cash	240.2	9.8	0.4	1.3	(9.4)	(0.0)	0.0	0.0
% gross debt in capital structure (incl debt equiv) (1)	57.4%	60.0%	59.3%	57.7%	58.6%	57.7%	58.2%	58.8%
EBIT interest coverage	2.98	3.12	3.13	3.08	3.00	2.35	2.21	2.08
Cash flow/adjusted total debt (1)	0.20	0.18	0.18	0.20	0.19	0.17	0.16	0.16

SENSITIVITY ANALYSIS

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various adverse scenarios. The assumptions used in this stress test are not based upon any information provided by the Company, or DBRS expectations.
Assumptions: CUL's EBITDA declines 10% in Year 1 and remains flat thereafter; capital expenditures remain flat at $450 million per year; other investments are reduced to zero; any free cash flow deficit is debt financed at an interest rate of 8.7% (average interest rate paid over the last three years).

Under the above assumptions, CUL would face a free cash flow deficit of just over $100 million annually, which DBRS assumes would be debt financed. The required debt financing would not be significantly dissimilar from CUL's recent debt financing requirements and, consequently, would not have a dramatic impact on its capital structure. Under the above assumptions, CUL's share of debt to capital would increase to just under 59% by Year 3 from the current 57.4%. CUL's EBIT interest coverage would fall sharply to just over 2.0 times by Year 3 from the current 3.0 times, but would remain in line with a number of other Canadian utilities. Cash flow/total debt would decline as well, but would remain above 0.15 times.

OPERATING LINES OF CREDIT

At June 30, 2001, the Company had credit lines of $1,392.0 million ($521.6 million specifically for CU Inc.), including $1,188.5 million ($400 million specifically for CU Inc.) available on a committed basis (long-term and short-term committed basis). CUL has a $200 million commercial paper program, which is fully backed by committed bank lines.

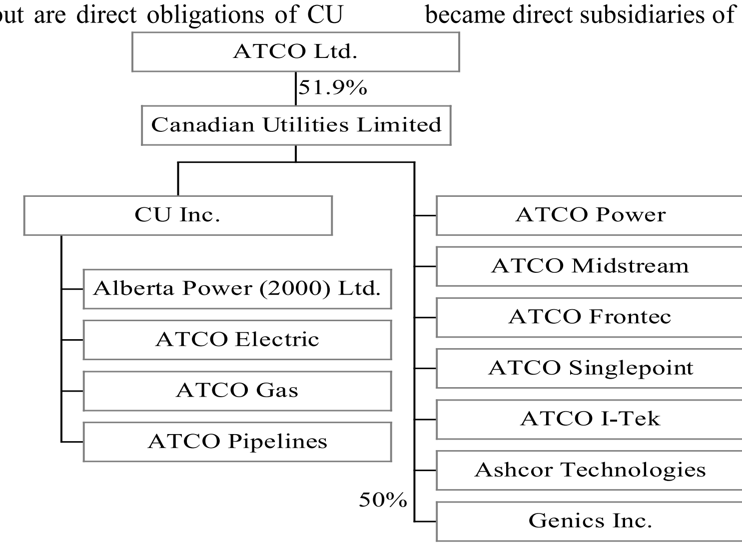
DEBT MATURITY SCHEDULE

($ millions)	2001	2002	2003	2004	2005
Recourse	24.3	71.2	155.0	100.0	125.0
Non-recourse	26.7	27.8	29.4	27.7	32.4

Two of CU Inc.'s debt issues ($90 million of 9.85% October 2006 and $100 million of 10.25% December 2006) are redeemable in 2001 and another ($125 million of 12% October 2007) is redeemable in 2002. The high coupon rates will encourage redemption, and we expect this to happen.

CORPORATE STRUCTURE

Effective July 1, 1999, Canadian Utilities Limited implemented a corporate re-organization that separated regulated and non-regulated utility businesses. CU Inc., a new wholly owned subsidiary, was created to hold the common shares and debentures of the regulated gas and electric operating subsidiaries. DBRS credit ratings of Canadian Utilities Limited, prior to July 1st, were associated with the debt obligations (publicly held) of the various regulated utility operations. Accordingly, the credit ratings and ratings history formerly associated with Canadian Utilities Limited have been assigned to CU Inc. The outstanding preferred shares will continue to be held by Canadian Utilities Limited, but are direct obligations of CU Inc.'s respective regulated operating subsidiaries.Effective January 1, 2001, an internal reorganization was completed. The operations and assets of Northwestern Utilities Limited were transferred to ATCO Gas and Pipelines Ltd. (comprised of ATCO Gas division and ATCO Pipelines division). Furthermore, as a result of the deregulation of the electricity market in Alberta, CU Inc.'s previously regulated generation assets were transferred from ATCO Electric to Alberta Power (2000) Ltd. These generation assets were deregulated through a system of long-term PPAs. Furthermore, Ashcor Technologies (formerly a subsidiary of ATCO Electric) and Genics Inc. (formerly a subsidiary of ATCO Frontec Corp.) became direct subsidiaries of Canadian Utilities Limited.



Canadian Utilities Limited

(Consolidated)

Balance Sheet

($ millions)

Assets	As at December 31 2000	1999	1998	**Liabilities & equity**	As at December 31 2000	1999	1998
Cash + equivalents	154.1	67.5	66.8	Short-term debt	365.5	176.7	276.1
Accounts receivable	629.2	340.5	352.1	A/P + accr'ds	745.1	302.2	323.8
Inventories	135.6	120.2	101.4	Current liabilities	1,110.6	478.9	599.9
Deferred gas & electricity costs	222.9	21.8	6.0	Deferred credits	215.3	198.7	180.4
Other	41.1	13.3	18.4	Long-term debt	1,841.2	1,666.0	1,433.3
Current assets	1,182.9	563.3	544.7	Non-recourse debt	360.0	395.4	422.7
Net fixed assets	4,007.0	3,847.7	3,802.0	Retract. pfd shares	0.0	50.0	200.0
Deferred electricity costs	86.0	3.5	0.0	Perpetual pfd shares	336.5	320.6	266.9
Other	114.2	114.1	90.5	Shareholders' equity	1,526.5	1,419.0	1,334.0
Total	5,390.1	4,528.6	4,437.2	Total	5,390.1	4,528.6	4,437.2

Ratio Analysis	12 mos. ended	For years ended December 31						
Liquidity Ratios	June 2001	2000	1999	1998	1997	1996	1995	1994
Current ratio	0.98	1.07	1.18	0.91	1.14	1.06	1.17	0.89
Accumulated depreciation/gross fixed assets (1)	-	34.2%	33.3%	32.1%	31.4%	30.1%	28.4%	27.2%
Cash flow/total debt (incl debt equiv) (2)	0.20	0.19	0.20	0.18	0.18	0.18	0.14	0.14
Cash flow/capital expenditures (3)	1.07	1.21	1.51	1.14	1.27	1.73	1.12	1.50
Cash flow-dividends/capital expenditures (3)	0.83	0.93	1.15	0.86	0.95	1.30	0.82	1.02
% gross debt in capital structure (incl debt equiv) (2)	57.4%	58.6%	57.7%	59.3%	60.0%	60.2%	65.3%	63.0%
Common equity in capital structure (incl equiv) (2)	42.6%	41.4%	42.3%	40.7%	40.0%	39.8%	34.7%	37.0%
Common dividend payout	50.0%	50.1%	54.5%	54.6%	54.8%	55.2%	61.1%	64.8%
Coverage Ratios (4)								
EBIT interest coverage	2.98	3.00	3.08	3.13	3.12	3.05	2.76	3.12
EBITDA interest coverage	4.13	4.16	4.31	4.28	4.21	4.07	3.69	4.18
Fixed-charges coverage	2.60	2.60	2.54	2.44	2.36	2.23	1.96	2.01
Earnings Quality/Operating Efficiency								
Operating margin	15.3%	20.3%	24.9%	28.1%	27.3%	29.8%	30.0%	28.7%
Net margin	5.9%	7.8%	9.1%	9.7%	9.4%	9.4%	9.0%	8.8%
Return on avg equity	15.2%	15.4%	14.5%	14.7%	14.9%	14.9%	14.1%	13.7%
Approved ROE - ATCO Electric (electric)	#	#	#	#	#	11.25%	11.88%	11.88%
Approved ROE - ATCO Gas & Pipelines North	#	#	#	#	#	11.88%	11.88%	11.88%
Approved ROE - ATCO Gas & Pipelines South	*	9.38%	9.38%	9.38%	10.50%	12.25%	12.25%	12.25%

(1) Excludes amortization of customer contributions. (2) "Excess" common equivalents treated as debt. (3) Net of customer contributions.

(4) Before capitalized interest, AFUDC, debt amortizations. # Negotiated settlements. * 11.5% requested for ATCO Gas South and 12.0% requested for ATCO Pipelines South.

Canadian Utilities Limited

Consolidated Income Statement	12 months ended	6 months ended		For years ending December 31			
($ millions)	Jun. 2001*	Jun. 2001*	Jun. 2000*	2000*	1999	1998R	1997
Regulated gas & electric	2,678.2	1,585.1	895.4	1,988.5	1,708.3	1,551.8	1,573.5
Power generation	618.1	349.4	158.1	426.8	246.2	193.0	174.8
Other businesses	620.0	353.6	240.7	507.1	252.5	206.3	178.8
Corporate	0.7	0.4	0.4	0.7	0.7	0.7	0.5
Revenues	3,917.0	2,288.5	1,294.6	2,923.1	2,207.7	1,951.8	1,927.6
Expenses:							
Fuel + purchased power	589.8	379.3	139.0	349.5	255.0	201.6	193.8
Cost of gas	1,645.9	1,078.4	438.9	1,006.4	552.8	376.3	400.8
Operating + maintenance	704.3	319.3	249.2	634.2	542.2	515.6	510.5
Property + franchise taxes	134.1	87.0	53.0	100.1	78.2	101.3	103.9
Depreciation	242.0	120.4	117.1	238.7	229.5	207.9	192.7
Operating costs	3,316.1	1,984.4	997.2	2,328.9	1,657.7	1,402.7	1,401.7
Operating income	600.9	304.1	297.4	594.2	550.0	549.1	525.9
Interest: recourse	184.6	92.1	84.7	177.2	154.9	144.1	138.6
Interest: non-recourse	26.0	14.6	16.8	28.2	30.8	36.8	36.8
Non-cash financial charges & cap. int.	(16.1)	(7.8)	(5.5)	(13.8)	(8.2)	(13.6)	(9.4)
Interest + dividend income	(27.2)	(18.2)	(12.6)	(21.6)	(21.2)	(17.3)	(20.7)
Other (income)/expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net interest expense	167.3	80.7	83.4	170.0	156.3	150.0	145.3
Pre-tax income	433.6	223.4	214.0	424.2	393.7	399.1	380.6
Income taxes	183.8	90.7	86.3	179.4	172.1	180.5	168.1
Net income before pfd divd.	249.8	132.7	127.7	244.8	221.6	218.6	212.5
Less: preferred dividends	17.0	8.5	8.3	16.8	14.9	10.4	12.4
retractable preferred dividends	0.0	0.0	0.6	0.6	6.6	18.0	18.6
Net income available to common	232.8	124.2	118.8	227.4	200.1	190.2	181.5

* Revenue breakdown not comparable to previous years due to internal reorganization.

	12 months ended	6 months ended		For years ending December 31			
Consolidated Cash Flow Statement	Jun. 2001	Jun. 2001	Jun. 2000	2000	1999	1998R	1997
Net income (after pfd)	232.8	124.2	118.8	227.4	200.1	190.2	181.5
Depreciation	242.0	120.4	117.1	238.7	229.5	207.9	192.7
Other non-cash adjustments	43.7	27.1	7.3	23.9	35.5	27.6	27.4
Operating cash flow	518.5	271.7	243.2	490.0	465.1	425.7	401.6
Less: common dividends	116.5	59.5	57.0	114.0	109.0	103.9	99.5
capital expenditures (net of contrib)	485.7	218.7	138.8	405.8	308.9	372.6	317.0
Cash flow before working capital	(83.7)	(6.5)	47.4	(29.8)	47.2	(50.8)	(14.9)
Less: working capital changes	(182.6)	(350.0)	(27.5)	139.9	38.4	72.0	20.1
Free cash flow	98.9	343.5	74.9	(169.7)	8.8	(122.8)	(35.0)
Less: other investments	38.7	41.4	29.0	26.3	42.2	(5.2)	1.4
Plus: net financing	180.0	56.5	63.1	186.6	34.7	118.0	46.2
Net change in cash	240.2	358.6	109.0	(9.4)	1.3	0.4	9.8

CU Inc.

Current Report: July 30, 2001
Previous Report: October 20, 2000

RATING

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Rating	Trend	Rating Action	Debt Rated
A (high)	Stable	Confirmed	Unsecured Debentures/Medium Term Notes
Pfd-2 (high)	Stable	Confirmed	Preferred Shares*

RATING HISTORY

	Current	2000	1999	1998	1997	1996	1995
Unsecured Debentures	A (high)	A (high)	AA (low)	AA (low)	AA (low)	AA (low)	AA (low)
Preferred Shares*	Pfd-2 (high)	Pfd-2 (high)	Pfd-1 (low)	Pfd-1 (low)^	Pfd-1	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.'s ("the Company") unsecured debt and preferred shares are confirmed at A (high) and Pfd-2 (high), both with Stable trends. Despite the unfavourable regulatory decisions delivered in 2000, the Company continued to generate relatively strong and stable operating cash flows. Leverage and coverage ratios remain favourable although they deteriorated in 2000 as a result of the above-mentioned factor and the higher working capital requirements due to the high gas prices, which necessitated increased short-term financing. However, most of the key debt ratios have since improved as gas costs have been recovered and short-term debt has been paid down.

CU Inc.'s operating income should resume its normal growth pattern in line with the economic growth in Alberta, assuming no further unfavourable regulatory decisions. Earnings growth should also generally benefit from the higher approved ROEs applicable to electricity generation subject to the power purchase agreements ("PPAs"). Cash flows from operations are expected to be sufficient in the medium term to finance the Company's projected annual capital expenditure requirements of $300 million - $350 million. External financing may be required in late 2001 if the Company chooses to redeem the two redeemable debenture issues. Over the longer term, CU Inc. will continue to face the challenge of dealing with the cumbersome regulatory environment in Alberta, as well as facing increased business risk associated with the PPAs implemented January 1, 2001. Deregulation is not expected to have a significant impact on CU Inc.'s financial profile as it remains predominantly involved in regulated businesses (PPAs are not considered regulated), which have greater stability than non-regulated businesses.

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:

- Increased business risk from PPAs
- Cumbersome regulatory environment
- Generation earnings to decline over long term as assets under the PPAs near the end of their useful lives

FINANCIAL INFORMATION

	12 mos ending	As at December 31				
	Mar. 2001	2000	1999	1998R	1997	1996
Fixed charges coverage (times)	2.38	2.40	2.56	2.55	2.45	2.28
% debt in capital structure (incl debt equiv)	52.4%	55.6%	53.7%	55.3%	57.6%	58.7%
Cash flow/total debt (times) (incl debt equiv)	0.21	0.19	0.21	0.20	0.19	0.18
Cash flow/capital expenditures (times)	1.67	1.52	1.93	1.50	1.41	1.78
Operating income ($ millions)	432.4	440.4	450.9	468.2	451.3	466.2
Segmented net income - electric	n.a.	93.0	90.2	86.5	84.2	72.0
- gas	n.a.	60.1	65.8	68.8	67.4	72.9
Consolidated net income ($ millions) (after pfd)	151.5	153.1	156.0	155.3	151.6	144.9
Operating cash flow ($ millions)	364.9	366.6	366.1	353.1	335.4	326.8
Electricity sales (GWh)	10,319	10,392	10,068	10,188	10,089	9,760
Gas volumes throughtputs (bcf)	915.7	928.1	828.8	771.5	669.2	656.8

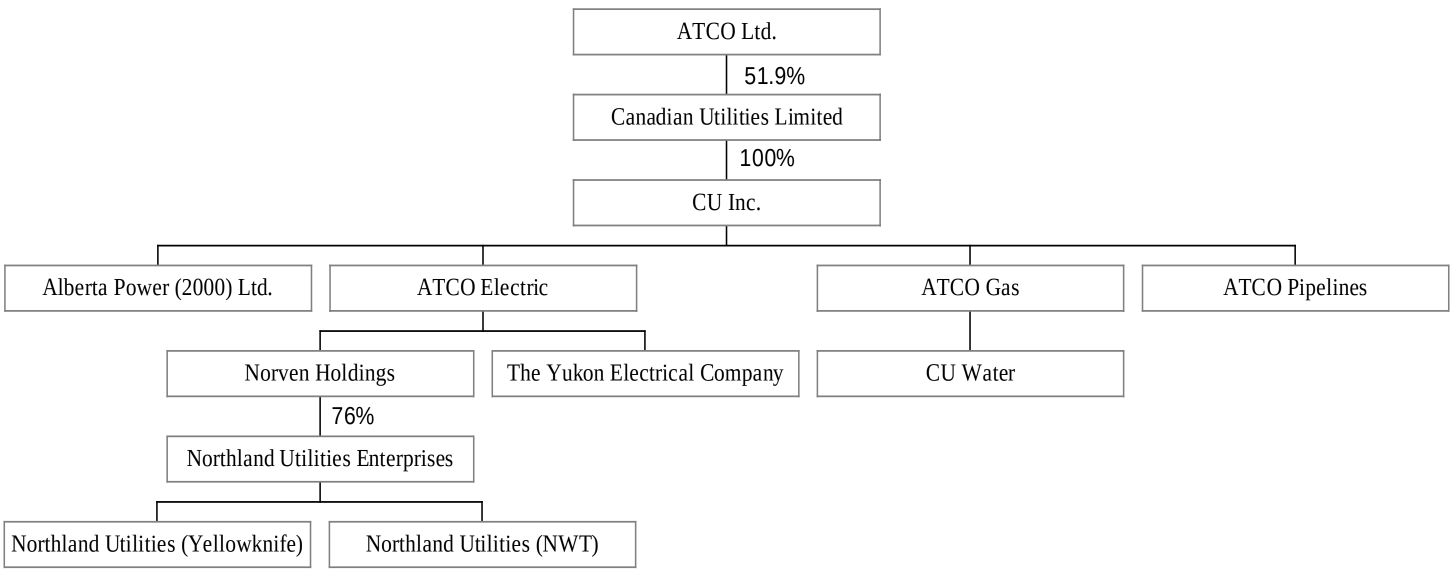
*1993-98 pro forma, 1999 6-mos. (Jan-Jun) combined operations of regulated gas + electric utilities, 6-mos. (Jul-Dec) consolidated operations of CU Inc.

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 Northwest Territories, as well as electricity generation assets that were regulated prior to deregulation of the Alberta electricity market. CU Inc. is wholly owned by Canadian Utilities Limited (see separate report).

CORPORATE STRUCTURE

Effective July 1, 1999, Canadian Utilities Limited implemented a corporate re-organization that separated regulated and non-regulated utility businesses. CU Inc., a new wholly owned subsidiary, was created to hold the common shares and debentures of the regulated gas and electric operating subsidiaries. DBRS credit ratings of Canadian Utilities Limited, prior to July 1, were associated with the debt obligations (publicly held) of the various regulated utility operations. Accordingly, the credit ratings and ratings history formerly associated with Canadian Utilities Limited have been assigned to CU Inc. The outstanding preferred shares will continue to be held by Canadian Utilities Limited, but are direct obligations of CU Inc.'s respective regulated operating subsidiaries.

Effective January 1, 2001, an internal reorganization was completed resulting in the new structure below. The operations and assets of Northwestern Utilities Limited were transferred to ATCO Gas and Pipelines Ltd. (composed of ATCO Gas division and ATCO Pipelines division). Furthermore, as a result of the deregulation of the electricity market in Alberta, CU Inc.'s previously regulated generation assets were transferred from ATCO Electric to Alberta Power (2000) Ltd. These generation assets were deregulated through a system of long-term power purchase agreements ("PPAs"). The PPAs allow for a stable recovery of costs plus profits.



REGULATION

Most of CU Inc.'s Alberta-based utility operations are regulated by the Alberta Energy and Utilities Board ("AEUB"). The Company's operations in the Yukon Territory and in the Northwest Territories are subject to regulation by the regulatory bodies in those jurisdictions.

Electricity: Bill 27 was passed in April 1998 to amend the *Electric Utilities Act* to provide a framework for an unbundled, deregulated and competitive market environment effective January 2001. Key features of the legislation and new environment that affect CU Inc. include: (1) *Retail Competition*, effective January 2001, 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 (a flow-through of commodity costs). This option is available for five years for residential and farm customers, and for three years for small commercial and small industrial customers. CU Inc. is not involved in retail marketing. (2) *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. (3) *Cost averaging of existing generation in service at December 1995 will continue under the long-term PPAs*. The PPAs incorporate annually adjusted, formula-based ROEs, consisting of a fixed 450 basis point risk premium above forecast 10-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 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. CU Inc.'s generation assets in service as at December 1995 were transferred from ATCO Electric to Alberta Power (2000) Ltd. effective January 1, 2001.

Gas Transmission & Distribution: Retail competition was introduced effective mid-1996, allowing customers to purchase gas directly from suppliers of their choice and contract separately for transportation services. Gas transmission and distribution operations, however, continue to be regulated by the AEUB. As with other gas distribution utilities in Canada, if a customer chooses to purchase gas directly from its gas utility, the cost of the gas is passed on to customers and, thus, has no impact on earnings.

Effective January 1, 2001, CU Inc. merged and restructured its two gas subsidiaries (formerly Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited) into two separate divisions of ATCO Gas and Pipelines Ltd.: (1) ATCO Pipelines, a transmission operation, which essentially provides gas transportation services, and (2) ATCO Gas, a distribution operation, which supplies and distributes gas. For regulatory purposes, however, separate accounts must be maintained for four new divisions (ATCO Gas North, ATCO Pipelines North, ATCO Gas South and ATCO Pipelines South) until December 31, 2004. In 1998, the AEUB approved a five-year (1998-2002) negotiated settlement for Northwestern Utilities Limited (now ATCO Gas North and ATCO Pipelines North), which is cost-of-service based and includes an incentive methodology. The agreement was re-opened in 2000 as the 1999 rate of return for ATCO Gas North exceeded the National Energy Board determined rate of return by more than the specified maximum amount. The re-opening was settled by negotiation.

A regulatory decision set Canadian Western Natural Gas Company Limited's (now ATCO Gas South and ATCO Pipelines South) 1997 and 1998 common equity component at 37% and its approved ROE at 10.50% for 1997 and 9.375% for 1998. In December 2000, the AEUB allowed for the continuation of the 9.375% ROE for ATCO Gas South and ATCO Pipelines South for both 1999 and 2000. For 2001 and 2002, ATCO Gas South has applied for an approved ROE of 11.50%, while ATCO Pipelines South has applied for an approved ROE of 12.00%. Decisions have not yet been rendered by the AEUB.

RATING CONSIDERATIONS

Strengths: (1) Most of the Company's utility operations (except electricity generation, which is protected by PPAs) are regulated, which contributes to relative earnings and balance sheet stability, and to a lesser extent cash flow stability, over the longer term. Both the electricity (for transmission and distribution operations) and gas operations (indefinitely) have deferral accounts, which allow for the full recovery of commodity costs although there is usually a time lag. Furthermore, the Company's generation assets are all subject to PPAs, which provide for a certain degree of earnings stability.

(2) CU Inc. has consistently generated operating cash flows well in excess of capital expenditure requirements. Key cash flow ratios (operating cash flow/total debt, operating cash flow/capital expenditures, and operating cash flow-dividends/capital expenditures) remain some of the strongest within the electric and gas distribution industry.

(3) Industry sector diversification (gas and electricity) helps earnings stability. Furthermore, it places the Company in a favourable position to benefit from the trend in energy convergence. CU Inc. is the only utility in Canada, aside from the provincial government-owned utilities in Manitoba, Saskatchewan and to a lesser degree, Québec, that is equally active in the gas and electricity industries.

(4) Despite its holding company structure, CU Inc. (Canadian Utilities Limited prior to the corporate reorganization) has a history of not leveraging against operating subsidiaries' assets.

(5) The provincial economy is one of the strongest in Canada both fiscally and economically, although given the resource-based nature of the economy, growth tends to be more volatile. Strong oil and gas prices over the past two years and heightened pipeline activity have enhanced exploration and production activity, and continue to contribute to a favourable earnings growth outlook for CU Inc.

Challenges: (1) The implementation of the PPAs and the underlying characteristics of the agreements increase CU Inc.'s business risk. (a) The generators are obligated to meet specified output commitments. Generators will be penalized (required to make a payment to the PPA holder) if actual output is below the specified capability of the respective unit. However, if generators exceed these thresholds, they are entitled to an incentive payment. (b) Forecast capital expenditures for the next 20 years under the PPAs may be below actual requirements. The variance is not recoverable. (c) Establishing who is at fault and defining "force majeure" in the event of an unplanned shutdown may be difficult and could lead to disputes and litigation if the problem is severe enough.

(2) Transmission and distribution operations (gas and electricity) continue to be regulated and, therefore, subject to the cumbersome regulatory environment in Alberta that includes significant time lags in the absence of negotiated settlements. The time delay in having requests approved or denied can have significant impacts on working capital (and cash) requirements over the short term.

(3) Earnings from CU Inc.'s generation assets are expected to decline over the longer term as the assets near the end of their contracted lives under the PPAs.

EARNINGS

Income Statement ($ millions)	12 Mos. Mar. 2001	Three months ended Mar. 2001	Mar. 2000	For years ended December 31* 2000	1999	1998R	1997	1996
Revenues - gas	n.a.	n.a.	n.a.	1,454.0	1,013.5	887.0	915.0	834.7
Revenues - electric	n.a.	n.a.	n.a.	794.0	706.0	675.9	664.9	657.1
Total revenues	2,806.7	1,147.4	588.7	2,248.0	1,719.5	1,562.9	1,579.9	1,491.8
Expenses								
Cost of gas	1,383.5	696.1	232.2	919.6	499.7	376.3	400.9	311.1
Fuel + purchased power	297.5	119.3	43.5	221.7	150.3	126.1	124.0	120.8
OM&A	378.0	92.8	86.0	371.2	322.7	312.7	325.8	327.5
Depreciation	193.5	52.4	53.9	195.0	187.2	179.3	174.4	168.0
Franchise + property taxes	121.8	53.4	31.7	100.1	108.7	100.3	103.5	98.2
Total operating costs	2,374.3	1,014.0	447.3	1,807.6	1,268.6	1,094.7	1,128.6	1,025.6
Operating income	432.4	133.4	141.4	440.4	450.9	468.2	451.3	466.2
Interest expense	162.8	41.8	41.0	162.0	145.5	141.2	137.5	146.1
Non-cash financial charges	(5.0)	(1.2)	(0.6)	(4.4)	(4.4)	(5.7)	(6.7)	(6.6)
Interest + other income	(11.9)	(4.5)	(0.6)	(8.0)	(3.6)	(3.8)	(4.5)	(4.1)
Net interest expense	145.9	36.1	39.8	149.6	137.5	131.7	126.3	135.4
Pre-tax income	286.5	97.3	101.6	290.8	313.4	336.5	325.0	330.8
Income taxes	121.7	42.1	44.4	124.0	139.7	156.8	146.4	152.6
Net income bef pfd dividends	164.8	55.2	57.2	166.8	173.7	179.7	178.6	178.2
Retract preferred dividends	0.0	0.0	0.6	0.6	6.6	18.0	18.6	27.8
Preferred dividends	13.3	3.3	3.1	13.1	11.1	6.4	8.4	5.5
Net income avail. to common shlders	151.5	51.9	53.5	153.1	156.0	155.3	151.6	144.9
Electricity sales (millions of kWhs)	10,319	2,611	2,684	10,392	10,068	10,188	10,089	9,760
Total gas volumes (bcf)	915.7	270.8	283.2	928.1	828.8	771.5	669.2	656.8

* 1993-98 proforma, 1999 6-mos. (Jan-Jun) combined operations of regulated gas + electric utilities, 6-mos. (Jul-Dec) consolidated operations of CU Inc.

The rate decisions rendered by the AEUB in 2000 relating to the years 1997 through to 2000 for the gas utility operations accounted for a large part of the 2.3% decline in the Company's operating income in 2000 to $440.4 million. A portion of the earnings impact from the decline in the approved ROE in 1997 and 1998 relative to 1996 was recorded against 2000 net income, while the AEUB decision to maintain the approved ROE for 1999 and 2000 at the 1998 rate reduced net income by $13.4 million in 2000. The 4.5% colder-than-normal temperatures in 2000 and higher electricity sales helped offset some of the negative earnings impact from the gas utility rate decision.

Outlook: Operating income and net income (after preferred dividends) should improve in 2001 and 2002 if the AEUB approves the Company's 2001 and 2002 rate applications for ATCO Gas South and ATCO Pipelines South. Earnings growth should also continue to benefit from the continued strong economic growth in Alberta and the higher approved ROEs applicable to electricity generation subject to PPAs. The recent approval by the AEUB for ATCO Gas to sell some of its smaller oil and gas-producing properties will likely have a limited impact on the Company's net earnings going forward. The AEUB did not approve ATCO Gas' sale of the Viking-Kinsella property nor its sale of its interest in the Beaverhill Lake and Fort Saskatchewan area properties. ATCO Gas and ATCO Electric are not involved in retail marketing and, therefore, have very limited exposure to commodity price risk.

FINANCIAL PROFILE

	12 Mos.	Three months ended		For years ended December 31*				
	Mar-01	Mar-01	Mar-00	2000	1999	1998R	1997	1996
Net income (after pref div.)	151.5	51.9	53.5	153.1	156.0	155.3	151.6	144.9
Depreciation	193.5	52.4	53.9	195.0	187.2	179.3	174.4	168.0
Other non-cash adjustments	19.9	2.4	1.0	18.5	22.9	18.5	9.4	13.9
Operating cash flow	364.9	106.7	108.4	366.6	366.1	353.1	335.4	326.8
LESS: common dividends	111.9	30.9	32.0	113.0	131.9	82.3	99.3	67.9
capital expenditures (net of contrib)	218.9	10.7	33.6	241.8	189.6	235.5	238.0	183.2
Cash flow before working capital	34.1	65.1	42.8	11.8	44.6	35.3	(1.9)	75.7
LESS: working capital changes	(45.4)	(263.2)	(77.8)	140.0	53.6	66.6	13.2	(29.4)
Free cash flow	79.5	328.3	120.6	(128.2)	(9.0)	(31.3)	(15.1)	105.1
LESS: other investments	35.2	3.4	5.8	37.6	33.2	0.5	4.2	(6.3)
PLUS: net debt financing	111.4	(119.5)	(46.4)	184.5	144.5	36.3	21.5	(102.2)
PLUS: net pfd equity financing	0.0	0.0	(34.1)	(34.1)	(96.3)			
PLUS: net common equity financing	0.0	0.0	0.0	0.0	0.0			
Net change in cash	155.7	205.4	34.3	(15.4)	6.0	4.5	2.2	9.2
Fixed charges coverage	2.38	-	-	2.40	2.56	2.55	2.45	2.28
Cash flow/adjusted total debt (1)	0.20	-	-	0.18	0.20	0.19	0.18	0.18
Cash flow/capital expenditures (2)	1.67	-	-	1.52	1.93	1.50	1.41	1.78

* 1993-98 proforma, 1999 6-mos. (Jan-Jun) combined operations of regulated gas + electric utilities, 6-mos. (Jul-Dec) consolidated operations of CU Inc.
(1) Perpetual pfd shares = 70% equity weighting, retractable pfd - 100% debt. (2) Net of customer contributions.

The Company's financial profile remained strong in 2000 despite a deterioration in key debt and cash flow ratios. Operating cash flows remained more than sufficient to fund capital expenditures in 2000. However, the higher natural gas prices in 2000 and the time lag in passing on the increased gas prices to consumers resulted in significantly higher working capital requirements. This had to be financed externally. As is the case for other regulated utilities, CU Inc.'s dividend payments are managed to maintain the equity component of the capital structure roughly in line with recent deemed levels (varies between 37% for ATCO Gas to 45% through the PPAs for ATCO Electric's generation assets). The Company's cash requirements, including debt maturities, were met through the issuance of $200 million in debentures, although it also increased its short-term notes payable.

CU Inc.'s cash flow/capital expenditures ratio (1.67 times for 12 months ended March 31, 2001) remains strong and has been relatively stable over the past five years (except for two years when capital expenditures fell, which led to a higher ratio). The Company's fixed charges coverage fell in 2000 after remaining stable during the previous three years due to the previously mentioned negative impact on 2000 earnings of the gas utility rate decisions.

Net debt in the capital structure (DBRS-adjusted) increased in 2000 to 57.7% from 55.9% in 1999 as a result of the higher debt levels. However, short-term debt fell significantly during the first quarter of 2001 in line with reduced working capital requirements, bringing the debt/capital ratio down to 54.7%.

Outlook: Going forward, the Company's fixed charges coverage should improve to its previous level of about 2.5 times as: (1) earnings growth returns to normal in the absence of further unfavourable regulatory decisions; and (2) interest costs decline due to the reduction in working capital requirements and, thus the reduced need for short-term financing. It is expected that CU Inc. will continue to generate sufficient operating cash flow over the next few years to finance its projected annual capital expenditures requirements of $300 million - $350 million. It may require external financing if it chooses to redeem two redeemable debt issues in the fall of 2001.

Key ratios should be positively affected over the medium term due to the increase in the allowed equity component for the electricity generation operations under the PPAs (Alberta Power) to reflect the higher risk associated with the more competitive market environment. However, over the longer term, the positive effect will diminish as the assets under the PPAs near the end of their useful lives.

OPERATING LINES OF CREDIT

As at March 31, 2001, bank lines totaled $521.6 million, of which (a) $400 million is available on a committed basis, backstopping a $400 million commercial paper program; and (b) $121.6 million is an uncommitted demand line of credit.

DEBT MATURITY SCHEDULE

	2001	2002	2003	2004	2005
(millions)	$7.2	$71.2	$61.0	$100.0	$125.0

Two debt issues ($90 million of 9.85% October 2006 and $100 million of 10.25% December 2006) are redeemable in 2001 and another ($125 million of 12% October 2007) is redeemable in 2002. The high coupon rates will encourage redemption.

CU Inc.

Balance Sheet
($ millions)

Assets	As at December 31 2000	1999	1998	Liabilities & Equity	As at December 31 2000	1999	1998
Cash + equivalents	51.1	0.0	0.0	Short-term debt	223.1	112.2	222.2
Accts receivable	562.7	287.8	278.6	A/P + accr'ds	623.4	198.3	242.6
Inventories	126.2	111.0	93.3	Long-term debt due 1 year	7.2	50.2	42.9
Prepaids + other	229.8	11.8	14.5	Current liabilities	853.7	360.7	507.7
Current assets	969.8	410.6	386.4	Deferred credits	93.9	85.0	66.5
Net fixed assets	3,150.6	3,088.3	3,095.2	Long-term debt	1,750.2	1,557.4	1,319.4
Deferred assets	86.0	3.5	8.9	Debt equiv pfd shares	0.0	50.0	200.0
Other assets	74.4	77.7	47.0	Perpetual pfd equity	256.5	240.6	186.9
				Shareholders' equity	1,326.5	1,286.4	1,257.0
Total	4,280.8	3,580.1	3,537.5	Total	4,280.8	3,580.1	3,537.5

Ratio Analysis	12-mos. ended	For years ended December 31 *						
Liquidity Ratios	Mar. 2001	2000	1999	1998R	1997	1996	1995	1994
Current ratio	1.32	1.14	1.14	0.76	0.97	0.92	0.97	0.87
Accumulated depreciation/gross fixed assets	-	37.4%	36.4%	35.1%	34.0%	32.5%	30.7%	29.4%
Cash flow/total debt (incl debt equiv)	0.21	0.19	0.21	0.20	0.19	0.18	0.16	0.15
Cash flow/adjusted total debt (a)	0.20	0.18	0.20	0.19	0.18	0.18	0.15	0.14
Cash flow/capital expenditures (1)	1.67	1.52	1.93	1.50	1.41	1.78	1.34	1.43
Cash flow-dividends/capital expenditures (1)	1.16	1.05	1.24	1.15	0.99	1.41	0.95	0.90
% debt in capital structure (incl debt equiv)	52.4%	55.6%	53.7%	55.3%	57.6%	58.7%	63.1%	64.8%
% adj. debt in capital structure (incl debt equiv)	54.7%	57.7%	55.9%	57.0%	58.9%	60.0%	63.9%	65.4%
Average coupon on long-term debt	-	8.96%	9.20%	9.70%	9.72%	10.02%	-	-
% hybrids/common equity	13.3%	13.5%	13.1%	10.4%	7.7%	8.0%	5.4%	4.5%
Common dividend payout	73.9%	73.8%	84.6%	53.0%	65.5%	46.9%	63.3%	78.0%
Coverage Ratios (2)								
EBIT interest coverage	2.73	2.77	3.12	3.34	3.31	3.22	3.08	3.17
EBITDA interest coverage	3.92	3.97	4.41	4.61	4.58	4.37	4.16	4.22
Fixed charges coverage	2.38	2.40	2.56	2.55	2.45	2.28	2.13	2.12
Earnings Quality / Operating Efficiency								
Operating margin	15.4%	19.6%	26.2%	30.0%	28.6%	31.3%	31.4%	29.1%
Net margin (after pfd)	5.4%	6.8%	9.1%	9.9%	9.6%	9.7%	9.7%	8.6%
Return on avg equity	11.4%	11.7%	12.3%	12.7%	13.1%	13.3%	13.7%	13.6%
Approved ROE - ATCO Electric (electric)	#	#	#	#	#	11.25%	11.88%	11.88%
Approved ROE - ATCO Gas & Pipelines North	#	#	#	#	#	11.88%	11.88%	11.88%
Approved ROE - ATCO Gas & Pipelines South	**	9.38%	9.38%	9.38%	10.50%	12.25%	12.25%	12.25%
Operating Statistics								
Electric generating capacity (MW)	1,162	1,312	1,388	1,387	1,452	1,446	1,446	1,439
Customer growth - electricity operations	-	2.2%	0.2%	1.7%	1.9%	1.7%	1.6%	1.7%
Customer growth - gas distribution operations	-	2.1%	2.4%	3.1%	2.5%	1.8%	1.6%	2.1%
Rate base growth - electricity operations	-	8.6%	2.0%	1.4%	-4.5%	1.5%	1.6%	-1.1%
Rate base growth - gas distribution operations	-	7.2%	4.0%	7.6%	3.1%	-0.6%	7.5%	6.9%
Degree day deficiency - % normal (Calgary)	-	105.6%	91.3%	98.0%	98.9%	120.0%	106.0%	100.0%
Degree day deficiency - % normal (Edmonton)	-	103.3%	92.2%	95.4%	98.6%	124.8%	107.6%	104.0%

* 1993-98 proforma, 1999 6-mos. (Jan-Jun) combined operations of regulated gas + electric utilities, 6-mos. (Jul-Dec) consolidated operations of CU Inc.

(1) Net of customer contributions. (a) perpetual pfd shares = 70% equity weighting, retractable pfd - 100% debt. (2) Before capitalized interest, AFUDC and debt amortizatior

Negotiated settlement. ** 11.5% requested for ATCO Gas South and 12.0% requested for ATCO Pipelines South.

Churchill Falls (Labrador) Corporation Limited

Current Report: October 3, 2001
Previous Report: September 20, 2000

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RATING

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

RATING HISTORY

	Current	2000	1999	1998	1997	1996	1995
First Mortgage Bonds – Series A, B	"A"	"A"	A (low)	A (low)	A (low)	A (low)	NR

RATING UPDATE

DBRS confirms the rating on Churchill Falls (Labrador) Corporation Limited's ("CF(L)Co" or "the Utility") First Mortgage Bonds at "A" with a Stable trend. 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 of 0.10¢ per kWh, and all-in costs of producing power of 0.20¢ 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 (under 0.30¢ per kWh) in the long-term contract between Hydro-Québec and CF(L)Co that runs until 2041. It is expected that CF(L)Co will continue to generate net earnings close to $30 million given the 1998 conclusion of a "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. While annual capital expenditures are projected to rise to $4 million-$7 million during much of the next fours years (relative to previous annual capital expenditures of $2 million-$3 million), the Utility should still be able to generate material free cash flow surpluses available for continued debt paydown, assuming there is no material increase in the dividend pay-out. Despite a decline in net income and operating cash flow in 2000 (largely due to higher maintenance costs), the Utility generated another material free cash flow surplus as the dividend pay-out fell significantly. This resulted in a further debt reduction, with the debt to capital ratio falling to 46.7%, the lowest of any government-owned utility and comparable to the private sector. While interest coverage remains reasonable at 1.73 times, it continues to be lower than its investor-owned peers due to the unfavourable terms of the long-term contract. DBRS expects continued improvement in key debt ratios as debt levels decline.

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:

- Tied to long-term power contract, with declining mill 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					
	2000	1999	1998	1997	1996	1995
EBIT interest coverage (times)	1.73	1.75	1.68	1.53	1.46	1.50
% debt in the capital structure	46.7%	49.5%	53.8%	55.2%	56.4%	58.1%
Cash flow/total debt (times)	0.14	0.14	0.12	0.10	0.09	0.09
Cash flow/capital expenditures (times)	13.11	21.61	16.53	21.57	15.21	12.69
Net income ($ millions)	26.7	28.8	28.8	21.6	19.1	21.6
Operating cash flow ($ millions)	43.6	45.8	45.6	39.2	36.6	39.8
Electricity sales (millions of kWhs sold)	34,601	33,807	36,878	33,131	28,411	29,450
Electricity revenues (cents per kWh sold)	0.28	0.27	0.25	0.26	0.28	0.29
Variable costs (cents per kWh sold)	0.10	0.08	0.07	0.08	0.09	0.09
Fixed costs (cents per kWh sold)	0.10	0.11	0.10	0.12	0.13	0.13
Avg. coupon on long-term debt	7.71%	7.71%	7.71%	7.70%	7.70%	7.72%

THE COMPANY

Churchill Falls (Labrador) Corporation Limited operates a 5,428 MW hydro-electric 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.

Rating Considerations

Strengths: (1) Under the terms of the original power contract signed in 1969, Hydro-Québec absorbs virtually all of the financial and marketing risk associated with the operation of the generating facilities at CF(L)Co. Under this contract, Hydro-Québec's commitments include: (a) acceptance of all available power the facility can generate; (b) absorption of exchange risk on the foreign currency debt above and beyond a specified ceiling; (c) payment of a "demand" charge on power (essentially a "take-or-pay" clause), effectively guaranteeing the project's debt obligations; and (d) the requirement to make advances in the form of either equity or loans to CF(L)Co in the event that available funds are insufficient to meet debt service obligations and other expenses. As such, DBRS considers the rating of CF(L)Co to be highly influenced by the rating assigned to Hydro-Québec.
(2) The facility's cost of construction was very low, which together with a hydro generation base and ample storage capacity places CF(L)Co among the lowest cost generators in the world. The development cost was just under $1 billion for 5,428 megawatts or $185,000 per megawatt. By contrast, Manitoba Hydro's highly successful Limestone station costs about $1.3 billion for 1,000 megawatts, or $1.3 million per megawatt, while Ontario Power Generation's Darlington plant costs $14 billion for 3,400 megawatts or $4.1 million per megawatt of generation capacity.
(3) CF(L)Co's balance sheet and coverage ratios are very strong relative to other government utilities, and are comparable to those of the private sector utilities.
(4) The "Guaranteed Winter Availability" contract (to 2041) with Hydro-Québec will provide an additional $1.1 billion in revenues over the life of the contract.

Challenges: (1) Although Hydro-Québec absorbed most of the risk associated with development of CF(L)Co, the contract is unfavourable, with electricity sold at a fraction of current market rates. Under the terms of the agreement, Hydro-Québec pays 0.27 cents per kWh until 2001, 0.25 per kWh through to 2016, and 0.20 cents per kWh thereafter to 2041. Hydro-Québec presently resells this power for at least ten times this amount. Two court challenges have failed to reverse the terms of the contract, which appears secure to the end of the contract in 2041.
(2) As power generation is entirely hydro-based, earnings are sensitive to rainfall and water flows.
(3) The high dividend payout is expected to continue over the foreseeable future, which limits the annual amount by which net debt can be reduced. While the shareholders' agreement signed in June 1999 places additional restrictions on the payment of dividends, the general policy remains to pay out common dividends to the extent of the excess cash in the Utility, subject to the terms of the long-term debt instruments. Preferred dividends are calculated as a proxy for provincial corporate income taxes.

Earnings

Income Statement (non-consolidated)	For years ended December 31					
(Cdn$ millions)	2000	1999	1998	1997	1996	1995
Energy - Exports	81.4	79.9	87.0	83.2	75.9	80.2
- Labrador	7.4	7.4	6.7	3.8	3.8	3.8
Energy revenues	88.8	87.3	93.8	87.0	79.7	84.0
Guaranteed winter availability	7.0	5.4	0.0	0.0	0.0	0.0
Non-energy	0.7	0.7	0.7	0.7	2.0	2.0
Total revenues	96.6	93.5	94.5	87.7	81.7	86.1
Expenses:						
Operating & administration	34.8	27.4	27.4	27.0	26.0	26.2
Depreciation	16.7	16.8	16.5	16.4	16.4	17.1
Rents + royalty fees	4.4	5.0	5.2	4.3	3.6	3.7
Total operating costs	56.0	49.3	49.1	47.7	45.9	47.1
Operating income	40.6	44.2	45.4	40.0	35.8	39.0
Interest expense	37.1	38.7	42.7	41.3	42.0	43.9
Non-cash financial charges	0.2	0.2	0.2	0.2	0.2	0.2
Other (income)/expense	(23.4)	(23.5)	(26.3)	(23.0)	(25.5)	(26.8)
Net interest costs	13.8	15.4	16.5	18.4	16.7	17.4
Income before equity income	26.7	28.8	28.8	21.6	19.1	21.6
Equity income (Twin Falls)	0.5	0.6	0.5	0.3	0.2	0.2
Net income	27.3	29.4	29.4	21.9	19.4	21.8

Earnings for the year declined slightly in 2000 to $27.3 million despite higher electricity sales (up 2.3% to 34.6 billion kWh) and lower interest costs as a result of the continued paydown in debt. The decline in earnings was entirely due to a significant increase in operating and administration costs (up 27% or $7.4 million) largely due to higher maintenance expenses, but also one-time factors (the change in accounting policy for recording employee future benefits and higher temporary wages).

Outlook*:* Earnings are expected to remain relatively stable going forward, but will be influenced by water levels as the amount of electricity available is a function of the amount of rainfall. Ongoing debt reduction from continued free cash flow surpluses should further reduce the Utility's interest costs and, therefore, continue to contribute positively to its net income.

FINANCIAL PROFILE

(Cdn$ millions)	2000	1999	1998	1997	1996	1995
	For years ended December 31					
Net income	27.3	29.4	29.4	21.9	19.4	21.8
Depreciation	16.7	16.8	16.5	16.4	16.4	17.1
Other non-cash adjustments	(0.4)	(0.4)	(0.3)	0.8	0.9	0.9
Operating cash flow	43.6	45.8	45.6	39.2	36.6	39.8
Plus: divid rec'd - Twin Falls	0.6	0.5	0.5	0.2	0.2	0.2
Less: dividends pd	15.5	21.1	25.3	21.8	14.8	16.9
capital expenditures	3.4	2.1	2.8	1.8	2.4	3.2
Gross free cash flow	25.3	23.1	17.9	15.8	19.6	20.0
Less: working capital changes	1.7	2.1	6.4	4.9	0.9	2.5
Free cash flow	23.6	21.0	11.6	10.9	18.7	17.5
Less: other investments	(5.1)	(4.3)	(13.9)	20.3	(0.3)	(0.3)
Plus: net financing	(29.7)	(27.6)	(25.8)	(23.9)	(22.2)	(20.8)
Net change in cash	(1.0)	(2.4)	(0.3)	(33.2)	(3.2)	(3.0)
Total debt	307.2	337.9	390.8	409.3	429.5	453.7
% debt in capital structure	46.7%	49.5%	53.8%	55.2%	56.4%	58.1%
EBIT interest coverage (times)	1.73	1.75	1.68	1.53	1.46	1.50
Cash flow/ total debt	0.14	0.14	0.12	0.10	0.09	0.09

The contribution from the Guaranteed Winter Availability contract has pushed sustainable operating cash flows up to around $45 million. Capital expenditures have ranged from only $2 million to $3.5 million annually over the past eight years, and dividends have been in the $15 million-$25 million range during that time. As a result, the Utility has been able to record annual gross free cash flow surpluses of $15 million-$25 million, which have been used to reduce debt. The consistent free cash flow surpluses have resulted in ongoing debt reduction, with the debt-to-capital ratio falling to 46.7% in 2000 from 49.5% the previous year, making Churchill Falls the strongest, from a balance sheet perspective, of all government-owned utilities in Canada. Interest coverage was basically unchanged in 2000 at 1.73 times despite the 8% drop in EBIT as interest costs also declined. With debt to capital below 50%, EBIT interest coverage should be closer to 2.5 times. However, it is limited by the low earnings because of the long-term power contract with Hydro-Québec at substantially below market rates.

Outlook: Capital expenditures are projected to increase to almost $7 million in 2001, and are expected to remain in the range of $2.5 million-$6 million in each of the four years thereafter to cover equipment upgrades and a computerized SCADA operating system. Financial leverage and interest coverage ratios should continue to improve as debt continues to be paid down. The amount of net debt paydown has averaged $25 million-$30 million annually, and is expected to continue. Annual sinking fund payments on the debt are currently expected to average $39 million per year.

OPERATING LINES OF CREDIT

The Utility has a $10 million operating line of credit.

DEBT MATURITY SCHEDULE

	2001	2002	2003	2004	2005
($ millions)	39	39	39	39	39

The above amounts are sinking fund installment requirements. Due to the contingent nature of these requirements, the above numbers are estimates.

Churchill Falls (Labrador) Corporation Limited

(Non-consolidated)

Balance Sheet
(Cdn$ millions)

Assets	2000	1999	1998	**Liabilities & Equity**	2000	1999	1998
	As at December 31				As at December 31		
Cash	6.3	5.7	7.3	Short-term debt	1.4	0.5	0.0
Receivables	38.1	33.6	34.7	Accts pay + accr'ds	11.8	10.1	14.5
Prepaid expenses	9.8	9.4	9.7	L.t.d. due in 1 year	42.7	38.3	37.6
Current assets	54.2	48.7	51.7	Current liabilities	55.8	48.8	52.1
Fixed assets	553.1	566.1	580.8	Long-term debt	263.1	299.2	353.2
Investments	7.3	12.9	17.5	Employee future benefi	6.5	0.8	0.0
Def'd charges	61.7	65.4	91.2	Shareholders' equity	350.7	344.2	335.9
Total	676.2	693.1	741.2	Total	676.2	693.1	741.2

Ratio Analysis	For years ended December 31							
Liquidity Ratios	2000	1999	1998	1997	1996	1995	1994	1993
Current ratio	0.97	1.00	0.99	1.15	1.94	2.05	2.43	2.46
Accumulated depreciated/gross fixed asset	40.2%	38.6%	36.8%	35.1%	33.4%	31.7%	30.0%	28.6%
Cash flow/total debt	0.14	0.14	0.12	0.10	0.09	0.09	0.09	0.10
Cash flow/capital expenditures	13.11	21.61	16.53	21.57	15.21	12.69	18.34	17.63
Cash flow-dividends/capital expenditures	8.50	11.78	7.44	9.63	9.08	7.34	11.11	8.99
% debt in capital structure	46.7%	49.5%	53.8%	55.2%	56.4%	58.1%	55.5%	57.1%
Average coupon on long-term debt	7.71%	7.71%	7.71%	7.70%	7.70%	7.72%	7.71%	7.71%
Common equity in capital structure	53.4%	50.5%	46.2%	44.8%	43.6%	41.9%	44.5%	42.9%
Common dividend payout (before extras.)	57.0%	71.7%	86.3%	99.6%	76.6%	77.3%	67.6%	81.3%
Coverage Ratios (1)								
EBIT interest coverage	1.73	1.75	1.68	1.53	1.46	1.50	1.44	1.56
EBITDA interest coverage	2.18	2.18	2.07	1.93	1.85	1.89	1.74	1.91
Fixed-charges coverage	1.73	1.75	1.68	1.53	1.46	1.50	1.44	1.56
Earnings Quality / Operating Efficiency								
Operating margin	42.0%	47.3%	48.0%	45.6%	43.8%	45.3%	48.3%	50.7%
Net margin	28.3%	31.4%	31.1%	25.0%	23.7%	25.4%	24.3%	28.2%
Return on avg equity (before extras.)	7.9%	8.6%	8.8%	6.6%	5.9%	6.7%	6.4%	8.0%
Profit returned to government (2)	63.0%	75.8%	88.4%	99.7%	80.2%	80.6%	72.6%	84.1%
GWh sold/employee	143.6	145.1	155.6	138.6	122.5	113.3	122.6	112.5
Generation								
Twin Falls capacity (MW)	225	225	225	225	225	225	225	225
Churchill Falls capacity (MW)	5,428	5,428	5,428	5,428	5,428	5,428	5,428	5,428
Exports: Hydro-Québec	30,268	29,674	32,793	30,301	25,748	26,693	27,413	29,909
Labrador sales	4,333	4,133	4,085	2,830	2,663	2,757	2,737	2,489
Total (GWh sold)	34,601	33,807	36,878	33,131	28,411	29,450	30,150	32,398
Less: transmission losses + internal use	649	804	773	747	692	622	606	661
Gross energy generated - GWh	35,250	34,611	37,651	33,878	29,103	30,072	30,756	33,059
Energy sales growth	2.3%	-8.3%	11.3%	16.6%	-3.5%	-2.3%	-6.9%	14.1%
Exports - % of total electricity generated	87.5%	87.8%	88.9%	91.5%	90.6%	90.6%	90.9%	92.3%
% of Nfld. & Lab. Hydro inc from CF(L)	50.1%	38.6%	26.4%	28.8%	30.4%	31.3%	41.1%	45.0%
Energy lost + used/energy generated	1.8%	2.3%	2.1%	2.2%	2.4%	2.1%	2.0%	2.0%
Peak demand (MW)	5,606	5,590	5,602	5,584	5,577	5,690	5,664	5,620
Demand/capacity	103.3%	103.0%	103.2%	102.9%	102.7%	104.8%	104.3%	103.5%

(1) Before capitalized interest, AFUDC and debt amortizations. (2) Includes all taxes, dividends and debt guarantee fees.

(cents per kWh sold)	For years ended December 31 2000	1999	1998	1997	1996	1995
Unit Revenue and Costs	(Ttotal may not add due to rounding)					
Exports	0.29	0.29	0.27	0.27	0.29	0.30
Domestic	0.17	0.18	0.16	0.14	0.14	0.14
Average electricity revenues	0.28	0.27	0.25	0.26	0.28	0.29
Ancillary revenues	0.00	0.00	0.00	0.00	0.01	0.01
Average revenues	0.28	0.28	0.26	0.26	0.29	0.29
Costs:						
Variable costs	0.10	0.08	0.07	0.08	0.09	0.09
Gov't levies	0.01	0.01	0.01	0.01	0.01	0.01
Net interest expense	0.04	0.04	0.04	0.06	0.06	0.06
Cash costs	0.15	0.14	0.13	0.15	0.16	0.16
Cash margin	0.13	0.14	0.12	0.12	0.13	0.13
Non-cash financial charges	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation	0.05	0.05	0.04	0.05	0.06	0.06
Pre-tax margin	0.08	0.09	0.08	0.07	0.07	0.07
Variable costs	0.10	0.08	0.07	0.08	0.09	0.09
Fixed costs (deprec, interest + levies)	0.10	0.11	0.10	0.12	0.13	0.13
Total costs	0.20	0.19	0.18	0.20	0.22	0.22

EPCOR Utilities Inc.

Current Report: November 16, 2001
Previous Report: October 31, 2000

RATING

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Rating	Trend	Rating Action	Debt Rated
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	2000	1999	1998	1997	1996	1995
Senior Unsecured Debentures	A (low)	A (low)	A (low)	A (low)	NR	NR	NR
Cumulative Redeemable Preferred Shares	Pfd-2 (low)	NR	NR	NR	NR	NR	NR

RATING UPDATE

DBRS is confirming the long-term debt rating on EPCOR Utilities Inc. ("EPCOR" or "the Utility") at A (low) and the preferred share rating of EPCOR Finance Corporation at Pfd-2 (low), both with a Stable trend. Key factors supporting the rating confirmation are as follows: (1) an expectation that EPCOR will manage expenditures and acquisitions to maintain debt-to-equity in the 60% to 65% range; and (2) a strong parent, the City of Edmonton, which DBRS rates AA (high), that is expected to take steps to protect a very significant investment, as any other shareholder would. EPCOR's earnings growth outlook over the next two years is favourable and will be driven by capacity expansions and various acquisitions during 2000 and 2001. However, given the implementation of deregulation, DBRS expects the Alberta electricity market will become increasingly more competitive as new capacity is brought on line. Primary challenges EPCOR faces over the longer term include the following. (1) Growing competitive pressures as a result of the implementation of retail competition. EPCOR's acquisitions of TransAlta Utilities Corporation's retail customer base in Alberta and WestCoast Capital and Union Energy's retail customer base in Ontario increase the Utility's exposure to retail pricing pressures; (2) Growing exposure to merchant power risks as new generation capacity is increasing the proportion of revenues from non-regulated power generation, although long-term bilateral contracts will reduce this risk; and (3) Operating risks associated with meeting the supply commitments under PPAs.

Operating cash flows are expected to fund the majority of its planned capital expenditure and acquisition program, with the remainder to be funded by proceeds from another preferred share offer in the new year. Over the medium term, favourable earnings growth is expected to lead to improved debt levels and coverage ratios. However, planned outages at certain generating facilities will pressure earnings in the fourth quarter.

RATING CONSIDERATIONS

Strengths:

- Regulated businesses and PPAs provide earnings stability
- Tight Alberta power supply-demand market, limited interconnections minimize competitive pressures
- Capacity expansions and acquisitions enhance earnings growth potential
- Fiscally strong and supportive parent (City of Edmonton)

Challenges:

- Growing exposure to higher risk, non-regulated activities, including merchant power and retail energy marketing
- Operating risks associated with PPAs
- Lack of access to common equity markets
- Cumbersome regulatory process

FINANCIAL INFORMATION

	12 mos. ended	For years ended December 31					
	Sept. 2001	2000	1999	1998	1997	1996	1995
Fixed-charges coverage (times)	3.28	1.98	1.84	1.93	1.82	1.81	1.74
% adj. debt in the capital structure	60.3%	65.7%	61.1%	60.7%	62.3%	64.6%	67.5%
Cash flow/total debt (times)	0.20	0.14	0.15	0.17	0.17	0.15	0.13
Cash flow/capital expenditures (times)	1.94	1.53	1.03	1.36	2.27	3.17	3.43
Net income ($ millions) (before extras.)	251.9	149.3	116.6	121.1	116.3	118.3	126.9
Operating cash flow ($ millions)	363.3	251.5	204.1	209.2	203.3	187.8	148.5
Electricity sales (millions of kWhs)	9,753	10,013	9,147	9,858	8,180	8,305	7,703
Electricity revenues (1) (cents per kWh sold)	-	13.13	9.84	8.93	10.00	9.91	6.85
Average coupon on long-term debt	-	9.14%	9.59%	10.27%	10.29%	10.26%	10.26%

(1) Excluding ancillary businesses.

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*: Various ownership interests in independent power plants in Alberta, B.C. and Washington; retail energy services including electricity, natural gas and water heater rentals; and wholesale energy marketing. EPCOR is wholly owned by the City of Edmonton.

RATING METHODOLOGY

The rating reflects both qualitative and quantitative considerations: (1) legislation, which protects against the risk of stranded assets and allows for the recovery of invested capital; (2) the relative financial strength of EPCOR Utilities Inc., as reflected in key financial ratios; and (3) the fiscal strength of EPCOR's parent, the City of Edmonton, although no formal guarantees exist.

Note that debt securities issued prior to June 1999 are a direct liability of the City of Edmonton. DBRS rates the City of Edmonton (see separate report) at AA (high).

MARKET ENVIRONMENT – ALBERTA

Bill 27 was passed in April 1998 to amend the 1995 Electric Utilities Act, to provide a framework for an unbundled, deregulated and competitive market environment. Key features of the legislation that affect EPCOR Utilities are as follows. (1) Cost recovery continues under the power purchase arrangements ("PPAs") ensuring that both the costs associated with the recovery of potential stranded assets and the benefits of any residual asset value accrue to all consumers during the 20-year life of the PPAs. 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 the owner is adequately compensated for the operating risks. The PPAs also incorporate financial incentives that encourage operating efficiencies, and penalties for failing to meet output availability requirements. Under the PPAs, deemed equity for EPCOR's formerly regulated generation assets has been set at 47.5%. (2) For *new generation* assets (those in service after December 1995), pricing is market based. (3) *Transmission* remains regulated by the AEUB with a negotiated allowed revenue basis for 2001 and 2002. (4) *Retail Competition* became effective January 2001, which allowed for the implementation of independent, negotiated arrangements. Large industrial customers have been permitted to purchase directly from the Pool, since April 1, 1999. The associated retail marketing operations became subject to an income tax levy effective January 2001. With the implementation of retail competition, retail marketing businesses now bear the price risk associated with electricity commodity prices. (5) *Water and electricity distribution* operations are regulated by the City of Edmonton. The approved ROE for electricity distribution is 11.5% on a 38% deemed equity, and the resulting revenue escalates at 85% of inflation through 2005. For water distribution, the ROE is 11.5% on a deemed equity of 40% and the resulting revenue escalates at 99.5% of inflation through 2005.

RATING CONSIDERATIONS

<u>Strengths</u>*:* (1) Regulated *businesses and PPAs provide a degree of stability to the Utility's earnings and cash flows*. PPAs also provide for higher returns, incorporating a 450 bp risk premium above ten-year Government of Canada bonds and the deemed equity component has been raised to 47.5%. In addition, the PPAs include a framework for the development of performance-based regulation. Currently, 1,701 MW of EPCOR's generating capacity is under PPAs and 180 MW (EPCOR's share) is unregulated.

(2) *Tight power supply-demand market conditions and limited interconnections minimize competitive pressures in the near-term* – Average load growth is estimated at 3% from 2001 to 2010, and new Alberta generation is required to satisfy this growth due to limited cross-border inter-tie capacity. Limited interconnection minimizes competitive pressures over the near term.

(3) *Capacity expansions and acquisitions enhance earnings growth potential* – EPCOR currently has a number of generating units under development, which will increase capacity by over 500 MW (EPCOR's share) by late 2005. With the November 2000 acquisition of TransAlta Utilities' retail customer base, EPCOR expanded to become the largest electricity retailer in Alberta with 620,000 customers. The recently announced acquisition of Westcoast Capital Corporation and Union Energy Inc. (from Westcoast Energy) expands EPCOR's customer base by 900,000, primarily in Ontario. This acquisition provides a foothold in the Ontario energy market, which is scheduled for deregulation in May 2002.

(4) *Fiscally strong and supportive parent* - DBRS rates the City of Edmonton at AA (high). Although it does not guarantee debt issued directly by the Utility, like any other investor, the City of Edmonton would likely take reasonable steps to protect its investment, should it become necessary.

(5) *Balance sheet and coverage ratios compare favourably to other government-owned electric utilities* - Government utilities average 70% debt to capital and 1.6 times fixed-charges coverage. EPCOR's key debt ratios are in the range of investor-owned utilities (57% debt-to-capital and 2.17 times fixed-charges coverage: DBRS industry averages for 2000).

<u>Challenges</u>*:* (1) *Growing exposure to higher risk, non-regulated activities, including merchant power and retail energy marketing* - Non-regulated business segments (i.e., new generation, retail electricity and natural gas marketing) will account for much of the Company's future growth, increasing EPCOR's potential exposure to competitive pressures and merchant power risk. Retail competition may result in some customer losses over the longer term.

(2) *Operating risks associated with PPAs* - (a) Generators have an 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 these thresholds are exceeded, generators are entitled to an incentive payment. (b) Forecast capital expenditures over the life of the PPAs may be below actual requirements. The variance is not recoverable from the PPA holder. (c) Establishing who is at fault and defining *force majeure* in the event of an unplanned shutdown has proven to be

difficult, and could result in disputes and litigation if the problem is severe enough. However, to mitigate some of risk associated with downtime due to equipment failure, EPCOR (i) has business interruption insurance, which limits the downside risk to a 45 day maximum waiting period for coverage; (ii) stores strategic spare parts at each of its generating facilities.

(3) *Lack of access to common equity markets* - DBRS does not expect the City of Edmonton to make regular equity injections, however they have allowed a reduction to the dividend payout ratio. Key debt ratios could come under pressure if internally generated cash flows are insufficient to finance growth and/or meet funding requirements.

(4) *Cumbersome regulatory process* - Alberta-based utilities are burdened by material time lags associated with the regulatory process, adding to the cost, complexity and uncertainty inherent in the current system. Effective 2001, this risk applies only to the regulatory rate option (RRO) which includes residential and small commercial power sales.

EARNINGS

		12 months	Nine months ended		For years ended December 31				
Segmented Information ($ millions)		Sept. 2001	Sept. 2000	Sept. 2001	2000	1999	1998R	1997R	1996R
Electricity - Generation	22%	756.2	526.6	455.6	685.2	426.2	407.8	369.3	354.3
Electricity - T&D	2%	82.9	55.7	39.6	66.8	59.5	472.7	449.0	468.3
Energy services	72%	2,431.2	2,271.2	402.5	562.5	414.3	-	-	-
Water distribution	3%	116.7	89.5	78.9	106.1	99.3	97.8	95.4	92.6
Other	0%	1.5	0.8	0.0	0.7	0.7	0.2	14.1	0.0
Total External Revenues		**3,388.5**	**2,943.8**	**976.6**	**1,421.3**	**1,000.0**	**978.6**	**927.7**	**915.3**
Electricity - *Generation*	37%	192.8	157.4	129.9	165.3	129.0	136.3	140.2	158.5
Electricity - *T&D*	8%	40.8	32.8	31.2	39.2	46.6	75.2	64.9	67.3
Energy services	47%	242.6	234.0	23.0	31.6	24.8	-	-	-
Water distribution	8%	40.1	31.3	29.7	38.5	38.4	41.1	43.6	38.0
Other	0%	2.3	0.9	(5.5)	(4.1)	(4.3)	(6.4)	1.7	(0.3)
Total Operating Income		**518.6**	**456.4**	**208.3**	**270.5**	**234.5**	**246.2**	**250.4**	**263.5**
Net interest expense		144.1	113.6	92.0	122.5	119.9	125.1	134.1	145.2
Income taxes		122.6	124.8	1.0	(1.2)	(1.8)	0.0	0.0	0.0
Net income before extras.		251.9	218.0	115.3	149.2	116.5	121.1	116.3	118.3
Extraordinary items		0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2
Net income		251.9	218.0	115.3	149.2	116.5	121.1	116.3	112.1
Electricity sold (millions of kWh)		9,546	7,508	7,975	10,013	9,147	9,858	8,180	8,305
Water sales (Megalitres)		115.6	87	87	115.6	113.3	115.1	108.9	107.5

For the 12 months ended September 30, 2001, earnings increased by 69% to $251.9 million from the year ended December 31, 2000. Factors contributing to the significant increase in earnings are as follows: (1) expanded retail and wholesale operations arising from the acquisition, in 2000, of retail customers rights and PPAs, which improved EBIT from energy services by more than seven fold over the year ended December 31, 2000; and (2) strong generation performance and the contribution of new generation, primarily the Joffre cogeneration plant. For the 12 months ending September 2001, EBIT from generation is up 17% from December 2000.

Effective January 1, 2001, EPCOR is required to pay amounts in lieu of income taxes to the provincial balancing pool on income derived from its generating plants under PPAs and its energy services operations. These costs are however, recoverable from the PPAs and do not impact earnings.

Outlook: Planned outages at certain generating facilities will pressure earnings in the fourth quarter. However, the following factors are expected to contribute to continued growth in consolidated earnings. (1) Higher energy sales from new non-regulated generating capacity. EPCOR plans the addition of over 500 MW (EPCOR's share) of new capacity over the next four years. This includes a 40% share in a 249 MW combined cycle gas plant in Frederickson, Washington, which is scheduled for commissioning in 2002 – with half of its output under a 20-year, 50% tolling arrangement. (2) A generous 450 basis-point risk premium on a 47.5% deemed equity (as of January 1, 2001) for formerly regulated generating capacity that is now subject to PPAs. (3) The addition of 900,000 customers, primarily in Ontario, from the purchase of Westcoast Capital and Union Energy in October 2001, will immediately add approximately $8 million to $10 million to annual earnings (after interest charges) from existing water heater rentals, HVAC services and retail gas sales. This acquisition provides EPCOR with the opportunity to grow earnings through offering complete energy cross-marketing to these customers following the opening of the Ontario electricity market in May 2002. (4) Tight supply-demand market conditions will continue to provide stability to electricity prices in Alberta until at least the end of 2002 when material new capacity becomes operational in the province. Note that prices have come down to normal historic levels over the latter half of this year (Q3 2001 average of $45/MWh), after peaking in late 2000 and early 2001 (Q3 2000 average of $177/MWh).

However, earnings growth in the near to medium term will be pressured by the following: (1) Exposure to merchant power risk is increasing as more unregulated capacity comes on line. The Utility plans to reduce this risk by securing long-term sales contracts for at least 50% of unregulated capacity. (2) Potential erosion of core retail customer base in Alberta resulting from new entrants competing in EPCOR's traditional service area. These pressures on earnings are however outweighed by the positive earnings growth factors, which are expected to contribute to a steady growth in earnings over the medium to long term.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

Cash Flow Statement	12 mos./Sept. 30	Year ended December 31				Stress Testing*		
($ millions)	2001	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	651.3	375.8	324.5	335.6	339.7	628.7	638.7	638.7
Net income (before extras.)	251.9	149.3	116.6	121.1	116.3	237.6	236.1	219.5
Depreciation & amortization	133.3	105.9	90.4	90.0	90.0	112.3	129.3	145.7
Other non-cash adjustments	(21.9)	(3.6)	(2.8)	(1.9)	(2.9)	0.0	0.0	0.0
Cash flow from operations	363.3	251.5	204.1	209.2	203.3	349.9	365.5	365.2
Less: Dividends paid (received)	87.7	70.5	70.5	67.0	66.9	90.5	100.5	110.5
Less: capital expenditures	187.3	164.3	198.6	153.9	89.6	250.0	250.0	250.0
Cash flow before working capital	88.3	16.7	(65.0)	(11.7)	46.9	9.4	15.0	4.7
Less: change in work. cap. and other adj. (1)	385.9	104.0	18.0	(9.2)	9.5	(201.3)	(108.8)	0.0
Gross free cash flow	(297.6)	(87.3)	(83.0)	(2.5)	37.4	210.6	123.7	4.7
Less: investments & other	106.4	353.7	0.0	0.0	0.0	250.0	250.0	250.0
Net free cash flow	(404.1)	(441.1)	(83.0)	(2.5)	37.4	(39.4)	(126.3)	(245.3)
Plus: preferred shares	150.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0
Change in debt: new/(repayments)	273.9	441.8	81.0	1.4	(80.5)	(60.6)	126.3	245.3
Change in net cash	19.8	0.7	(2.0)	(1.2)	(43.1)	0.0	0.0	0.0
Key Figures and Ratios:								
Total debt in capital structure	1,845.9	1,761.6	1,319.9	1,234.5	1,232.0	1,785.3	1,911.5	2,156.8
% debt in capital structure	60.3%	65.7%	61.1%	60.7%	62.3%	59.5%	58.6%	59.6%
EBITDA interest coverage (times)	4.13	2.76	2.55	2.63	2.48	4.40	4.63	4.32
EBIT interest coverage (times)	3.28	1.98	1.84	1.93	1.82	3.62	3.69	3.33
Cash flow/ total debt	0.20	0.14	0.15	0.17	0.17	0.20	0.19	0.17
Stress Test Assumptions:								
EBITDA growth						-5%	0%	0%
Interest rate (based on interest rate in 2000)						7.7%	7.7%	7.7%

*Each year in the stress testing is 12 months ending September 30.

(1) This includes deferred amounts which increased by $209.6 million over the nine months ended September 30, 2001.

Despite a 48% increase, to $363.3 million, in operating cash flow for the 12 months ended September 30, 2001, over the same period last year, net free cash flow decreased significantly to a deficit of $404.1 million for the period. While operating cash flows were sufficient to cover capital expenditures, key factors contributing to the negative free cash flow are: (1) The $247.9 million investment in Alberta PPAs. (2) The $105.9 million acquisition of TransAlta Utilities' retail customer base. (3) An increase in non-current deferred amounts receivable associated with the 2001 deferral accounts (pending regulatory approval) and net increases in non-cash working capital. Despite negative free cash flows, financial leverage decreased to 60.3% and other key debt ratios improved over the year ended December 31, 2000. The improved leverage was primarily a result of EPCOR's issuance of $150 million in preferred shares in Q2 2001 and approximately $110 million in increased cash flow from operations. EPCOR's debt-funded acquisition, announced October 22, 2001, of Westcoast Capital and Union energy for $176.7 million will increase debt levels to slightly above 62% and have only a marginal impact on other ratios.

Outlook: Operating cash flows should continue to improve as a result of recent (and planned) retail energy acquisitions and generating capacity expansions. Operating cash flow will remain adequate to cover dividend payments to the City of Edmonton, growing by $10 million per annum until a 60% payout is reached, and the majority of its plannded capital expenditure and acquisition program. EPCOR has indicated that its expected external funding requirements will be met with a combination of preferred shares and public debentures. Key debt ratios could come under some pressure if growth initiatives are funded entirely with debt securities, but DBRS expects favourable retained earnings growth will maintain the debt to equity ratio in the 60%-65% range. Over the medium term, favourable earnings growth is expected to lead to a general improvement in debt levels and coverage ratios.

Sensitivity Analysis:

DBRS stress test the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Company, nor DBRS expectations concerning the future performance of the Company.

The following scenario has been analyzed: (1) EBITDA decreases by 5% in Year 1 and remains constant thereafter; (2) dividend payments are $90.5 million in Year 1 and increase by $10 million per year; (3) capital expenditures plus acquisitions (investments and other) are $500 million in all years; (4) 50% of earnings contribution from the WestCoast acquisition will occur in Year 1 and the full amount (approximately $20 million before interest costs) will occur in remaining years; and (5) any free cash flow deficit is debt financed. Under this scenario, EPCOR will generate sufficient operating cash flow to support dividend requirements to the City of Edmonton, but will require debt financing to assist in funding its capital expenditure and acquisition program. Debt ratios will continue to weaken under such adverse conditions. EPCOR would have to reduce capital expenditures and other investments, or use preferred share financing to maintain its current credit profile.

Operating Lines of Credit

$550 million in unsecured lines of credit, of which $200 million is committed until August 2002 and $300 million is committed until December 2003.
Additional unsecured, extendible bank lines of $325 million, which is used for credit support of commodity exposure.

Debt Maturity Schedule

	2001	2002	2003	2004	2005
($ millions) (incl. sinking fund payments)	86.7	69.6	64.4	55.4	57.4

Public debt securities issued directly by EPCOR Utilities Inc. are redeemable prior to maturity.

EPCOR Utilities Inc.

Balance Sheet
($ millions)

Assets	Sept. 2001	2000 (As at December 31)	1999 (As at December 31)	Liabilities & Equity	Sept. 2001	2000 (As at December 31)	1999 (As at December 31)
Accounts receivable	659.9	307.8	135.0	Short-term debt	404.5	590.2	265.3
Inventories	30.7	23.8	20.6	Accts. pay. + accr'ds	429.5	361.8	187.3
Prepaids	8.5	1.5	1.0	Current liabilities	834.0	952.0	452.5
Current assets	699.1	333.1	156.6	Other liabilities	57.5	5.6	9.1
Net fixed assets	2,299.1	2,232.7	2,183.2	Income tax & PILS	141	2	0
PPAs	231.7	247.8	0.0	Long-term debt	1,441.4	1,171.4	1,054.6
Deferred receivable	311.4	101.8	0.0	Preferred shares	150.0	0.0	0.0
Customer service rights/goodwill	101.5	105.7	0.4	Retained earnings	1,067.4	919.5	840.8
Other assets	48.5	28.9	16.7				
Total	3,691.3	3,050.0	2,357.0	Total	3,691.3	3,050.0	2,357.0

Ratio Analysis (1)	12 mos. ended	For years ended December 31						
Liquidity Ratios	Sept. 2001	2000	1999	1998R	1997R	1996R	1995	1994
Current ratio	0.72	0.35	0.35	0.30	0.47	0.35	0.40	0.44
Accumulated depreciated/gross fixed assets	-	27.7%	26.5%	26.7%	25.5%	23.5%	19.6%	19.1%
Cash flow/adjusted total debt	0.20	0.14	0.15	0.17	0.17	0.15	0.13	0.08
Cash flow/capital expenditures (2)	1.94	1.53	1.03	1.36	2.27	3.17	3.43	1.49
Cash flow-dividends/capital expenditures (2)	1.47	1.10	0.67	0.92	1.52	2.12	2.51	0.87
Average coupon on long-term debt (3)	-	9.14%	9.59%	10.27%	10.29%	10.26%	10.26%	10.27%
% adjusted debt in capital structure	60.3%	65.7%	61.1%	60.7%	62.3%	64.6%	67.5%	71.5%
Common dividend payout (before extras.)	23.4%	47.6%	61.4%	55.3%	57.5%	52.7%	31.4%	37.5%
Coverage Ratios (4)								
EBIT interest coverage	3.28	1.98	1.84	1.93	1.82	1.81	1.74	1.38
EBITDA interest coverage	4.13	2.76	2.55	2.63	2.48	2.33	2.16	1.73
Fixed-charges coverage	3.28	1.98	1.84	1.93	1.82	1.81	1.74	1.38
Earnings Quality / Operating Efficiency								
Operating margin	15.3%	19.0%	23.5%	25.2%	27.0%	28.8%	42.8%	38.2%
Pre-tax margin (before extras.)	11.1%	10.4%	11.5%	12.4%	12.5%	12.9%	23.7%	21.5%
Return on avg equity (before extras.)	70.2%	16.8%	14.0%	15.7%	16.1%	19.0%	24.3%	22.8%
Allowed ROE - EPCOR Power	10.29%	9.25%	9.25%	*	*	11.25%	11.88%	12.50%
Profit returned to government (bef extras.)	44.8%	59.8%	71.9%	68.2%	69.8%	67.1%	46.9%	53.9%
Regulated rate base (millions)	-	$1,218.5	$1,248.0	$1,251.9	$1,239.0	$1,272.6	$1,203.2	$939.5
Operating Statistics								
Generating capacity (IPP) - MW	180	180	-	-	-	-	-	-
Generating capacity (regulated)	1,701	1,701	1,701	1,701	1,701	1,701	1,701	1,701
Water sales (Megalitres)	115.6	115.6	113.3	115.1	108.9	107.5	108.9	-
Energy generated + purchased:								
Coal	6,289	6,233	6,333	6,344	6,252	6,828	6,817	6,265
Natural/methane gas	4,075	4,485	3,530	4,261	2,596	2,285	1,811	2,538
Hydro	104	57	0	0	0			
Gross energy generated	10,468	10,775	9,863	10,605	8,848	9,113	8,628	8,803
Plus: purchases	0	0	0	0	0	0	0	0
Energy generated + purchased	10,468	10,775	9,863	10,605	8,848	9,113	8,628	8,803
Less: line losses + internal use	715	762	716	747	668	808	925	928
Total - GWh sold	9,753	10,013	9,147	9,858	8,180	8,305	7,703	7,875
Total energy sales growth	-	9.5%	-7.2%	20.5%	-1.5%	7.8%	-2.2%	36.0%
Energy lost + used/energy gen + purch	-	75.6%	79.0%	76.4%	83.2%	87.0%	91.5%	85.8%
Peak demand/total installed capacity	-	56.9%	61.3%	60.5%	59.3%	58.4%	61.7%	60.1%

(1) The City of Edmonton amalgamated its water purification and electric utility operations in 1996 to form EPCOR Utilities Inc.
Results prior to 1996 reflect the operations of Edmonton Power Inc. (electric utility) and are not directly comparable. Edmonton Power was reorganized in January 1999 to separate the generation, transmission, distribution and retail operations.

(2) Capital expenditures are net of customer contributions.

(3) DBRS estimate.

(4) Before capitalized interest, AFUDC and debt amortizations.

* Negotiated settlement.

EPCOR Utilities Inc.

Income Statements ($ millions)	12 mos. ended Sept. 2001	Nine months ended Sept. 2001	Nine months ended Sept. 2000	For years ended December 31 2000	1999	1998R	1997R	1996R
Generation	756.2	526.6	455.6	685.2	426.2	407.8	371.1	358.5
T&D and technologies (1)	645.5	55.7	39.6	629.4	473.8	472.7	449.0	468.3
AEEMA-ASPRDA recovery/(cost)	0.0	0.0	0.0	0.0	0.0	0.0	(1.8)	(4.1)
Net electricity revenues	1,401.7	582.3	495.2	1,314.6	900.0	880.5	818.2	822.6
Energy services	1,868.7	2,271.2	402.5	0.0	0.0	0.0	0.0	0.0
Water utility	116.7	89.5	78.9	106.1	99.3	97.8	95.4	92.6
Other	1.5	0.8	0.0	0.7	0.7	0.2	14.1	0.0
Net revenues	3,388.6	2,943.8	976.6	1,421.4	1,000.0	978.6	927.7	915.3
Expenses:								
OM&A	372.8	277.9	183.7	278.6	195.3	177.9	157.7	152.1
Power purchases	1,990.2	1,869.4	279.0	399.8	279.3	277.3	285.3	290.8
Fuel costs	328.0	200.6	192.3	319.7	153.2	138.3	96.9	81.6
Municipal + franchise taxes	45.7	34.1	35.3	46.9	47.2	48.9	47.3	51.8
Depreciation	133.3	105.4	78.0	105.9	90.4	90.0	90.0	75.5
Total operating costs	2,869.9	2,487.4	768.3	1,150.8	765.4	732.4	677.3	651.8
Operating income	518.6	456.4	208.3	270.5	234.6	246.2	250.4	263.5
Interest expense	157.8	113.6	92.0	136.2	127.3	127.6	137.0	145.0
Non-cash financial charges	(14.4)	0.0	0.0	(14.4)	(8.0)	(3.0)	(3.6)	(0.6)
Other (income)/expense	0.6	0.0	0.0	0.6	0.6	0.5	0.7	0.7
Net interest expense	144.1	113.6	92.0	122.5	119.9	125.1	134.1	145.2
Pre-tax income	374.5	342.8	116.3	148.0	114.8	121.1	116.3	118.3
Income taxes	122.6	124.8	1.0	(1.2)	(1.8)	0.0	0.0	0.0
Net income before extras.	251.9	218.0	115.3	149.3	116.6	121.1	116.3	118.3
Extraordinary items	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(6.2)
Net income	251.9	218.0	115.3	149.3	116.6	121.1	116.3	112.1
Net income after pfd dividends	251.9	218.0	115.3	149.3	116.6	121.1	116.3	112.1
Depreciation	133.3	105.4	78.0	105.9	90.4	90.0	90.0	75.5
Other non-cash items	(21.9)	(18.6)	(0.3)	(3.6)	(2.8)	(1.9)	(2.9)	0.2
Operating Cash Flow (2)	363.3	304.8	193.0	251.5	204.1	209.2	203.3	187.8
Less: dividends	87.7	70.1	52.9	70.5	70.5	67.0	66.9	62.3
Capital expenditures (net of contrib)	187.3	149.6	126.6	164.3	198.6	153.9	89.6	59.2
Cash flow before working capital	88.3	85.1	13.5	16.7	(65.0)	(11.7)	46.9	66.2
Less: working capital + other adj.	385.9	318.8	36.9	104.0	18.0	(9.2)	9.5	(34.2)
Free cash flow	(297.6)	(233.7)	(23.4)	(87.3)	(83.0)	(2.5)	37.4	100.5
Less: other investments	106.4	0.6	247.9	353.7	0.0	0.0	0.0	0.0
Plus: preferred shares	150.0	150.0	0	0	0	0	0	0
Plus: net financing (3)	273.9	103.1	271.0	441.8	81.0	1.4	(80.5)	(104.1)
Net change in cash	19.8	18.8	(0.3)	0.7	(2.0)	(1.2)	(43.1)	(3.7)

(1) Prior to 1998 excludes Technologies.
(2) 1991-95 adjusted to reflect change in reporting format.
(3) Includes short-term debt commencing in 1998.

Owned & Installed Capacity	2000 Megawatts*	2000 %	2005F Megawatts*	2005F %
Genesee (coal)	820	43.6%	820	33.3%
Clover Bar (natural gas/methane gas)	660	35.1%	660	26.8%
Rossdale (gas)	221	11.7%	0	0.0%
Subtotal regulated/PPA (Alberta)	1,701	**90.4%**	1,480	**60.2%**
Rossdale (gas)	-	-	221	9.0%
Taylor Coulee (hydro)	6	0.3%	6	0.3%
Brown Lake (hydro - BC)	7	0.4%	7	0.3%
Joffre (natural gas)	166	8.8%	166	6.8%
Weather Dancer (wind)	1	0.1%	1	0.0%
Subtotal unregulated	180	**9.6%**		
Total Owned Capacity - 2000	1,881	100.0%		
Under Development				
Frederickson I, Washington (natural gas)	2002		100	4.1%
Waste heat plant (heat)	2003		27	1.1%
Miller Creek (hydro)	2003		29	1.2%
Combined cycle (natural gas)	2004		116	4.7%
Genesse 3, Hydro 3, & Cogen	2005		306	12.4%
Subtotal unregulated - 2005			979	**39.8%**
Total Owned Capacity - 2005			2,459	100.0%

*Note: Capacity (in MW) represents EPCOR's share of ownership.

ENMAX Corporation

Current Report: November 30, 2001
Previous Report: February 28, 2001

RATING

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Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Confirmed	Corporate Debt*

RATING HISTORY (as at Dec. 31)

	Current	2000	1999	1998	1997	1996
Corporate Debt*	A (low)	A (low)	NR	NR	NR	NR

*Highest credit rating applicable to the direct senior public obligations of ENMAX Corporation.

RATING UPDATE

DBRS is confirming the corporate debt rating for ENMAX Corporation ("ENMAX" or "the Company") at A (low) with a Stable trend. Earnings were up almost sevenfold for the 12 months ended September 30, 2001 over the same period last year largely due to the extremely high average Alberta Power Pool prices during the first half of 2001 and from higher sales volumes due to strong domestic growth and the start of exports to the U.S. However, such earnings growth is not expected to continue given the sharp decline in Power Pool prices and in margins in Q3 2001, which are expected to remain lower in the foreseeable future. Leverage and other key ratios have improved significantly as substantial free cash flow allowed for a 39% reduction in total debt compared to the end of 2000.

The Company's outlook remains favourable given (1) its low-cost generation capacity through power purchase arrangements (PPAs), (2) its large and growing customer base in an economically strong service area of Alberta – Calgary, and (3) its financially strong parent, the City of Calgary (rated at AA), which provides a potential source of support, although no formal guarantee exists. However, earnings volatility will increase as a result of its growing exposure to higher risk, non-regulated activities such as retail energy marketing, including the natural gas business it entered in October 2001. In addition, ENMAX faces the challenge of securing a new supply contract to replace the Wabamun PPA that expires in January 2004. However, some earnings stability will be provided by its regulated transmission and distribution businesses, which should account for about 40% of earnings on a normalized basis, and by its six-month to five-year fixed-price contracts primarily to commercial and light industrial customers.

In July 2001, Calgary City Council decided to pursue opportunities to sell ENMAX. However, on October 23, 2001, a newly elected Council decided to discontinue the existing process, and conduct further studies on the proposed sale. A final report will be submitted to Calgary City Council by April 2002.

RATING CONSIDERATIONS

Strengths:

- Regulated businesses and fixed-price contracts provide a degree of earnings stability
- Demand requirements hedged with PPAs
- Minimal regulatory burden; favourable ROE
- Financially strong parent (City of Calgary - AA)
- Strong franchise area with favourable growth outlook

Challenges:

- Growing exposure to higher risk, non-regulated activities
- Supplier risk associated with PPAs
- Lack of access to public equity markets

FINANCIAL INFORMATION

	12 mos.	For years ended December 31				
	Sept. 2001	2000	1999	1998	1997R	1996R
Fixed-charges coverage (times)	8.73	2.62	3.98	5.15	4.59	2.40
% debt in the capital structure	27.5%	60.9%	30.5%	33.4%	38.1%	32.4%
Cash flow/total debt (times)	1.16	0.14	0.51	0.59	0.45	0.30
Cash flow/capital expenditures (times)	3.86	1.09	1.26	2.93	3.23	1.58
Net income ($ millions) (before extras.)	238.4	44.5	44.5	65.2	52.1	21.3
Operating cash flow ($ millions)	375.9	75.4	73.0	93.2	77.4	42.8
Electricity sold (GWh)	8,699	7,500	7,162	6,980	6,867	6,644
Average coupon on long-term debt	7.70%	7.77%	9.04%	9.08%	9.34%	10.11%

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 approximately 400,000 customers in Calgary, Red Deer, Lethbridge, and several other smaller communities in Alberta; and (3) ENMAX Encompass, which provides billing and customer service for ENMAX and a number of municipalities. ENMAX Corporation is wholly owned by the City of Calgary.

MARKET ENVIRONMENT – ALBERTA

Bill 27 was passed in April 1998 to amend the 1995 Electric Utilities Act, to provide a framework for an unbundled, deregulated and competitive market environment. Key features of the legislation that affect ENMAX are as follows. (1) **Generation:** As of January 1, 2001, ENMAX has hedged its projected demand load for at least the next two years with two separate PPAs. 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 the owner is adequately compensated for the operating risks. For new generation assets (those in service after December 1995), pricing is market-based.

(2) **Transmission:** The Transmission Administrator (TA) is the sole provider of system access service to the interconnected electric system in Alberta. Municipally owned transmission facilities, such as ENMAX, have tariffs approved by the Department of Energy ("DOE") and investor-owned transmission facilities have tariffs approved by the Alberta Energy and Utilities Board ("AEUB"). These tariffs set out the rates charged to the TA for use of the transmission facilities and provide the owner with a recovery of costs and a return on capital. Based on a pending DOE decision, ENMAX anticipates earning an ROE equal to the 30-year Government of Canada bond yield plus 350 basis points on a deemed equity of 35%. This is consistent with the ROE earned by Transmission Facility Owners regulated by the AEUB.

(3) **Distribution:** ENMAX's distribution system is regulated by the City of Calgary, while investor-owned distribution is regulated by the AEUB. A regulated Distribution Access Tariff ("DAT") provides for a recovery of costs and a return on capital, including a return on mid-year equity of 10%.

(4) **Retail Competition**, which became effective January 1, 2001, allows for the implementation of independent, negotiated arrangements. Large industrial customers have been permitted to purchase directly from the Pool, since April 1, 1999. The associated retail marketing operations became subject to an income tax levy effective January 2001. With the implementation of retail competition, retail marketing businesses now bear the price risk associated with electricity commodity prices. In order to protect customers in the transitional phase between regulation and competitive retail markets, the Alberta government established a Regulated Rate Option (RRO) for residential and small commercial customers. Residential customers are able to remain on the RRO until the end of 2005, while small commercial customers are able to remain until the end of 2003. ENMAX Energy has been appointed to provide the RRO in Calgary and five other municipalities. The Alberta government has currently fixed the commodity price of electricity at 11¢ per kWh for RRO customers, which provides a favourable spread over ENMAX's fixed-electricity costs under its PPAs.

RATING CONSIDERATIONS

<u>Strengths</u>: (1) *Regulated businesses and fixed-price contracts provide a degree of earnings stability* – About 40% of ENMAX's normalized operating earnings are generated from "regulated" distribution and transmission assets. In addition, about 20% of ENMAX's earnings will be generated from margins locked in under the six-month to five-year fixed-price contracts signed primarily with commercial and light industrial customers. These businesses provide for a degree of earnings stability over the longer term.

(2) *Electricity demand requirements are hedged with long-term, low-cost power supply contracts* - With the acquisition of two PPAs in 2000, ENMAX has hedged current demand needs. The Company will, however, have to make new supply arrangements for a portion of demand needs as a substantial component of these PPAs expire in two years.

(3) *Minimal regulatory burden* – Transmission is regulated by the Alberta Department of Energy and distribution is regulated by the City of Calgary. Allowed returns for distribution regulated business has been somewhat higher than what other utilities have been allowed by the provincial regulator (AEUB). However, in the event that ENMAX is privatized, its distribution and transmission will fall under the regulatory regime of the AEUB.

(4) *Financially strong parent* - The City of Calgary is rated AA by DBRS. As the sole owner of the Company, Calgary can be expected to protect its investment, and is a potential source of support. However, no formal guarantee exists.

(5) *Strong franchise area with favourable growth outlook* - Calgary has experienced strong growth over the last five years, while ongoing diversification has reduced its sensitivity to the energy sector. The city's growth outlook remains favourable given the economic diversification, low tax burden, high standard of living and healthy population growth.

<u>Challenges</u>: (1) *Growing exposure to higher risk, non-regulated activities* - In the new competitive environment, electricity retailers bear the price risk associated with commodity costs for the portion of power needs that are not hedged by PPAs. Non-regulated business segments, such as retail energy marketing, will account for part of ENMAX's future growth, increasing the Company's exposure to competitive pressures and increasing its earnings volatility. Also, retail competition may result in some customer losses over the longer term. A material loss of customers would strain profit margins and adversely affect earnings.

(2) *Supplier risk associated with PPAs* - (a) Generators have an obligation to meet specified availability commitments. PPA holders are required to make an availability incentive payment to generators if the declared availability is above a designated target availability. However, generators are required to make a payment to the PPA holder if actual

availability is below the target availability. (b) Establishing who is at fault and defining *force majeure* in the event of an unplanned shutdown has proven to be difficult. One of the generating units under ENMAX's PPAs (Wabamun) underwent a forced outage in 2000 and remained out of service until June 2001. The *force majeure* claim by the operator (TransAlta Utilities) is currently in binding arbitration. ENMAX has claimed that it is entitled to net payments amounting to approximately $69 million, as it was forced to make other supply arrangements at much higher prices during the outage period. A decision by the arbitrators is expected early in 2002.

(3) *Lack of access to public equity markets* – ENMAX is owned by the City of Calgary and does not have access to the equity markets. Key debt ratios and balance sheet strength would come under pressure if internally generated cash flows were insufficient to finance growth and/or meet funding needs.

(4) *Earnings sensitive to interest rates* – Approved/negotiated ROE for transmission is linked to prevailing interest rates. The ROE tends to be set lower during periods of lower or declining interest rates, having a negative effect on earnings from the transmission business.

EARNINGS

($ millions)	12 mos. ended	9 months ended		Year ended December 31 (1)				
	Sept. 2001	Sept. 2001	Sept. 2000	2000	1999	1998	1997	1996
Regulated (ENMAX Power)								
Operating revenues		198.8	131.1					
Operating costs		131.4	91.4					
EBITDA		86.8	62.4					
EBIT		67.4	39.7					
Net income		53.3	31.8					
Unregulated (ENMAX Energy & ENMAX Encompass) (2)								
Operating revenues		409.7	43.8					
Operating costs		168.2	34.8					
EBITDA		322.7	9.6					
EBIT		241.5	9.0					
Net income (2)		200.7	8.9					
Consolidated (including intercorporate transfers)								
Operating revenues	653.6	578.9	176.3	251.0	199.3	203.9	170.8	142.6
Operating costs	367.1	305.1	142.7	204.7	149.2	132.4	110.2	114.0
EBITDA	402.5	374.9	59.1	86.7	86.4	108.1	89.1	56.9
EBIT	296.1	273.8	33.6	55.9	57.9	80.1	65.4	34.3
Net income	238.4	218.7	24.8	44.5	44.5	65.2	73.9	21.3

(1) Revenues, costs, and earnings were not separated into "regulated" and "unregulated" businesses prior to January 1, 2001.

(2) A portion of the revenues and earnings from ENMAX Energy come from the Regulated Rate Option which remains in effect until 2005 Currently, about 37% of ENMAX Energy's volumes and 44% of its revenues come from the Regulated Rate Option.

For the 12 months ended September 30, 2001, earnings increased almost sevenfold to $238.4 million over the same period last year. Factors contributing to the significant increase in earnings are as follows. (1) A sharp increase in margins during the first half of 2001 resulting from the difference between extremely high Power Pool prices and wholesale supply costs (approximately one-third of 2001 retail sales volumes are sold at "default" priced based on a flow through of Alberta Power Pool prices). Power Pool prices, however, fell back to more normal levels in Q3 2001 as a result of mild weather, strong generation availability and a decline in natural gas prices. (2) The sale of surplus electricity to the U.S. for the first time, with its export licence commencing in January 2001. (3) Higher sales volumes from an increased customer base, as ENMAX commenced selling electricity to customers across Alberta in 2001.

Outlook: Power Pool prices are expected to remain at their lower level indefinitely due to low natural gas prices, the Balancing Pool continuing to bid output from the Clover Bar generating facility into the Power Pool at marginal cost, and to forecasts of continued mild weather. Lower market prices in both Alberta and the U.S. are expected to continue to put downward pressure on net earnings in the fourth quarter of 2001 and into 2002.

Over the medium to long term, earnings from regulated businesses (ENMAX Power) should remain relatively stable, with moderate growth expected from an expanding customers base. Similarly, the sensitivity of ENMAX Energy's earnings to prevailing Power Pool prices should also begin to stabilize as the Company has in place six-month to five-year fixed-price contracts with numerous commercial and light industrial customers and began offering in September 2001 one- to three-year fixed-price contracts to residential and small business customers eligible for the RRO. *Note: The AEUB is expected to conduct a review of the 2001 cost of supply delivered to RRO customers in order to outline future regulation. ENMAX has indicated that the outcome of this review could potentially have a significant impact on future corporate earnings.*

ENMAX Energy entered the retail natural gas business on October 1, 2001, by offering fixed-price contracts to residential and small business customers in Alberta. This new business should allow ENMAX to increase earnings through offering bundled energy products to its existing customers, although the volatility of earnings will increase.

ENMAX believes it is entitled to net payments amounting to approximately $69 million pertaining to the lost output from the Wabamun power plant, which it has not yet recorded as income. The final amount is pending the outcome of an arbitration hearing, and a decision is expected early in 2002.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

Cash Flow Statement	12 mos./Sept. 30	Year ended December 31				Stress Testing*		
($ millions)	2001	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	408.0	86.7	86.4	108.1	89.1	265.2	265.2	265.2
Net income (before extras.)	238.4	44.5	44.5	65.2	52.1	110.1	99.9	91.3
Depreciation & amortization	106.4	30.8	28.5	28.0	23.7	116.3	128.1	138.1
Other non-cash adjustments	31.2	0.0	0.0	0.0	1.6	0.0	0.0	0.0
Cash Flow from Operations	376.1	75.4	73.0	93.2	77.4	226.4	228.0	229.4
Less: dividends paid (received)	27.6	29.9	34.0	28.0	25.3	30.0	30.0	30.0
Less: capital expenditures	97.3	69.3	57.9	31.7	24.0	125.0	125.0	125.0
Cash Flow Before Working Capital	251.2	(23.8)	(18.9)	33.4	28.1	71.4	73.0	74.4
Less: change in working capital	(45.1)	(156.1)	5.9	(51.2)	29.0	0.0	0.0	0.0
Gross Free Cash Flow	296.2	132.2	(24.8)	84.6	(0.9)	71.4	73.0	74.4
Less: investments & other	151.8	465.6	0.8	0.0	30.0	75.0	75.0	75.0
Net Free Cash Flow	144.4	(333.4)	(25.6)	84.6	(30.9)	(3.6)	(2.0)	(0.6)
Plus: preferred shares	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Change in debt: new/(repayments)	(147.7)	388.1	(14.6)	(13.7)	9.1	3.6	2.0	0.6
Change in Net Cash	(3.2)	54.8	(40.2)	70.9	(21.8)	0.0	0.0	0.0
Key Figures and Ratios:								
Total debt in capital structure	323.4	529.7	143.2	157.8	171.6	327.0	329.0	329.7
% debt in capital structure	27.5%	60.9%	30.5%	33.4%	38.1%	26.0%	24.7%	23.7%
EBITDA interest coverage (times)	11.81	4.06	5.93	6.95	6.25	13.67	13.52	13.43
EBIT interest coverage (times)	8.73	2.62	3.98	5.15	4.59	7.67	6.99	6.44
Cash flow/ total debt	1.16	0.14	0.51	0.59	0.45	0.69	0.69	0.70
Stress Test Assumptions:								
EBITDA growth						-35%	0%	0%
Interest rate						6.0%	6.0%	6.0%

*Each year in the stress testing is 12 months ending September 30.

As a result of the high average Power Pool prices and higher sales volumes, free cash flow increased substantially for the twelve months ended September 30, 2001, to a surplus of $144 million. Surplus cash enabled ENMAX to reduce its leverage to 27.5% from 60.9% at December 31, 2000, resulting in a significant improvement to key debt ratios.

Outlook: Operating cash flows are expected to weaken as lower Power Pool prices reduce margins on electricity sales. However, internally generated cash flows will likely remain sufficient to finance dividends and a planned increase in capital expenditures, and should result in surplus free cash flow that may be used to pay down debt. Continued free cash flow surpluses are highly dependent on the future spread between ENMAX electricity costs fixed under the PPAs and market prices beyond 2001, along with future RRO regulation which has yet to be outlined by the AEUB.

In July 2001, Calgary City Council decided to pursue opportunities to sell ENMAX. However, on October 23, 2001, a newly elected Council decided to discontinue the existing process and establish a Special Committee of Council to conduct further studies on the proposed sale. A final report will be submitted to Calgary City Council by April 2002.

ENMAX, in partnership with Fording Coal Limited, has announced that it is investigating the feasibility of constructing a 400 MW coal plant in southern Alberta. A third partner would likely be brought in to build and operate the plant as neither Fording Coal nor ENMAX has the expertise. The proposed new plant would address ENMAX's future power needs given that one of the acquired PPAs expires in two years. A decision will likely be made in the new year on whether to proceed with the project, based on the results of the feasibility study. However, there will likely be a lag of at least one year between the maturity of the short-term PPAs and the commissioning of the proposed coal project. Also affecting the feasibility of the project is the fact that there is substantial new gas-based generation capacity being developed in Alberta.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Company, nor DBRS expectations concerning the future performance of the Company.

The following scenario has been assumed: (1) EBITDA decreases by 35% in Year 1 as the spike up during the first half of 2001 is not expected to be sustainable and then remains constant thereafter, (2) dividend payments are $30 million a year, (3) capital expenditures ($125 million) plus investments and other ($75 million) total $200 million a year, and (4) any free cash flow deficit is debt financed.

Under this scenario, ENMAX will continue to generate surplus operating cash flow after funding dividend payments and capital expenditures. However, given the growing importance of non-regulated businesses, ENMAX's earnings will becoming increasingly variable, which will cause operating cash flows to fluctuate.

OPERATING LINES OF CREDIT

ENMAX has a fully committed, Cdn$350 million line of credit used to backstop the Company's Cdn$350 million commercial paper program, and a Cdn$100 million operating line of credit.
ENMAX also has a letter of credit of $54.0 million to a third-party electric generator that may be drawn upon in the event it defaults on its obligations relating to the PPA contracts.

DEBT MATURITY SCHEDULE (as at September 30, 2001)

	2001	2002	2003	2004	2005	Thereafter
($ millions)	10.6	23.3	23.2	22.9	22.6	115.2
% of total long-term debt outstanding	4.9%	10.7%	10.7%	10.5%	10.4%	52.9%

POWER PURCHASE ARRANGEMENTS HELD BY ENMAX

ENMAX Energy has acquired the rights to market the physical output of 1,314 MW of generation capacity with the acquisition of two PPAs through the provincial government auction of electrical generation in 2000. Details of the PPAs are provided in the table below.

Supply Source	No. of Units	Capacity (MW)	Annual Volume* (millions of kWh)	Generator	Date of Expiration	Cost of PPA ($ millions)
Wabamun (coal)	4	548	3,800	TransAlta Utilities Corp.	Jan. 1, 2004	77.279
Keephills (coal)	2	766	5,900	TransAlta Utilities Corp.	Dec. 31, 2020	247.695
Total	6	1,314	9,700			324.974

*Volume entitlement in first year of PPA, volume entitlement decreases as the age of the generators increases.

ENMAX Corporation

Balance Sheet
($ millions)

Assets	Sep-01	2000	1999	Liabilities & Equity	Sep-01	2000	1999
		As at December 31					As at December 31
Cash + short-term investments	4.4	85.4	30.6	Short-term + l.t.d due 1 year	128.6	172.5	15.8
Acct receivable	199.6	127.4	92.9	A/P + accr'ds	157.8	249.6	61.5
Inventories	8.3	8.3	9.8	Customer deposits	8.9	6.9	7.4
Other	31.3	0.4	1.4	Current liabilities	295.3	429.0	84.7
Current assets	243.6	221.6	134.8	Other liabilities	8.9	3.1	1.5
Net fixed assets	483.1	443.2	404.8	Long-term debt	194.8	357.2	127.5
PPAs and rate riders	340.3	465.1	0.0	Shareholders equity	852.1	340.6	325.9
Future income taxes	284.1	0.0	0.0	Total	1,351.1	1,129.9	539.5
Total	1,351.1	1,129.9	539.5				

Ratio Analysis	12 mos.	For years ended December 31				
Liquidity Ratios	Sept. 2001	2000	1999	1998	1997R	1996R
Current ratio	0.82	0.52	1.59	2.00	1.83	1.05
Accumulated depreciation/gross fixed assets	-	43.4%	43.6%	43.1%	38.4%	37.3%
Cash flow/total debt	1.16	0.14	0.51	0.59	0.45	0.30
Cash flow/capital expenditures (1)	3.86	1.09	1.26	2.93	3.23	1.58
Cash flow-dividends/capital expenditures (1)	3.58	0.66	0.67	2.05	2.17	0.73
% debt in the capital structure	27.5%	60.9%	30.5%	33.4%	38.1%	32.4%
Average coupon on long-term debt	7.70%	7.77%	9.04%	9.08%	9.34%	10.11%
Common dividend payout	11.6%	67.1%	76.3%	43.0%	48.6%	108.9%
Coverage Ratios (2)						
EBIT interest coverage	8.73	2.62	3.98	5.15	4.59	2.40
EBITDA interest coverage	11.81	4.06	5.93	6.95	6.25	3.98
Fixed-charges coverage	8.73	2.62	3.98	5.15	4.59	2.40
Earnings Quality/Operating Efficiencies & Statistics						
Operating margin	43.8%	18.5%	25.1%	35.0%	35.5%	20.1%
Net margin (bef. extras.)	36.5%	17.7%	22.3%	32.0%	30.5%	14.9%
Return on avg. common equity	40.0%	13.4%	13.9%	22.0%	18.1%	8.0%
GWh sold/employee	7.2	7.3	10.5	10.1	10.1	8.4
Customers/employee	338	332	477	468	461	382
Customers/distribution lines	64	51	50	-	-	-
Operating costs/avg. customer (3)	$418	$346	$260	$273	$215	$234
Growth in customer base	18.4%	4.9%	1.0%	3.5%	3.2%	-

R = Pro forma reflecting the January 1998 incorporation of ENMAX.
(1) Net of customer contributions.
(2) Before capitalized interest, AFUDC and debt amortizations.
(3) Operating costs exclude municipal + property taxes.

Income Statement	12 mos. ended	9 months ended		For the year ended December 31				
($ millions)	Sept. 2001	Sept. 2001	Sept. 2000	2000	1999	1998	1997R	1996R
Residential	471.651	310.300	121.100	282.451	156.848	152.970	149.831	147.427
Small commercial	92.616	62.100	23.600	54.116	34.157	32.967	32.766	31.569
Medium & large users	656.919	573.100	213.100	296.919	273.003	260.921	251.734	245.166
Other	58.320	100.000	96.800	55.120	14.349	13.372	10.746	10.021
Gross electricity revenues	1,279.406	1,045.500	454.700	688.606	478.357	460.230	445.077	434.183
Power purchases	701.002	530.600	326.800	497.202	329.319	307.618	298.619	323.660
Net distribution revenues	578.404	514.900	127.900	191.404	149.038	152.612	146.458	110.523
Transmission revenues	26.666	20.000	20.000	26.666	26.292	27.683	24.302	32.091
Water utility revenues	48.555	44.000	28.400	32.955	23.952	23.594	0.000	0.000
Total revenues	653.625	578.900	176.300	251.025	199.282	203.889	170.760	142.614
Expenses:								
Operating, maintenance + administration	126.689	100.300	58.200	84.589	56.056	58.724	42.314	48.173
Municipal consent + access fees (1)	109.780	86.000	45.200	68.980	47.516	45.737	44.200	43.162
Depreciation	29.329	24.000	25.500	30.829	28.473	27.985	23.704	22.644
PPA amortization	77.100	77.100	0.000	-	-	-	-	-
Contractual services expense	24.208	17.700	13.800	20.308	17.154	-	-	-
Retail gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total operating expenses	367.106	305.100	142.700	204.706	149.199	132.446	110.218	113.979
Operating income (EBIT)	286.519	273.800	33.600	46.319	50.083	71.443	60.542	28.635
Interest expense	34.560	23.900	10.700	21.360	14.560	15.542	14.256	14.315
Non-cash financing charges	(9.981)	0.000	0.000	(9.981)	(1.126)	(0.610)	(0.981)	(1.331)
Other (income)/expense	(15.092)	(7.400)	(1.900)	(9.592)	(7.848)	(8.656)	(4.832)	(5.664)
Net interest expense	9.487	16.500	8.800	1.787	5.586	6.276	8.443	7.320
Pre-tax income	277.032	257.300	24.800	44.532	44.497	65.167	52.099	21.315
Income taxes	38.600	38.600	0.000	0.000	0.000	0.000	0.000	0.000
Net income before extraordinary items	238.432	218.700	24.800	44.532	44.497	65.167	52.099	21.315
Extraordinary items	0.000	0.000	0.000	0.000	0.000	0.000	(21.838)	0.000
Net income	238.432	218.700	24.800	44.532	44.497	65.167	73.937	21.315

Electricity Sales - Breakdown									
Residential	29%	2,297	1,780	1,664	2,181	2,063	1,997	1,960	1,932
Small commercial	5%	445	349	277	373	364	318	317	305
Medium & large users	64%	5,620	4,483	3,547	4,684	4,575	4,527	4,476	4,299
Other	2%	338	278	203	263	160	138	114	108
Total energy sold (millions kWh)		8,699	6,890	5,691	7,500	7,162	6,980	6,867	6,644
Total energy distributed (millions kWh)		8,699	6,890	5,691	7,500	7,162	6,980	6,867	6,644
Growth in electricity volumes		16.0%	-	-	4.7%	2.6%	1.6%	3.4%	4.2%

(1) Payments made in lieu of municipal + property taxes.

Great Lakes Power Inc.

Current Report: October 29, 2001
Previous Report: September 29, 2000

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RATING

Rating	Trend	Rating Action	Debt Rated
BBB (high)	Stable	Confirmed	Senior Unsecured Notes

RATING HISTORY (as at Dec. 31)

	Current	2000	1999	1998	1997	1996	1995
Senior Unsecured Notes	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)

RATING UPDATE

DBRS is confirming the long-term debt rating on Great Lakes Power Inc. ("Great Lakes" or "the Company") at BBB (high), with a Stable trend. Key factors supporting the rating confirmation are as follows. (1) Relatively stable earnings from diversified sources consisting of electric utility assets and an income-producing investment portfolio. (2) Over 90% of Great Lakes generating capacity is low-cost hydro-based, and is increasing with recent purchases and new plants under construction. (3) 80% of its electricity output is committed under long-term power sale agreements. Leverage increased slightly to 41.8% debt/capital at June 30, 2001, which is a reasonable level for an integrated electric company. Leverage will increase further with the purchase of six hydroelectric generating stations and related transmission assets in Maine for US$156.5, financed by 50% debt and 50% cash. EBIT interest coverage improved to 2.23 times at June 30 from 2.04 times at December 31, 2000, due to higher operating income from increased generating capacity and the resale of contracted gas purchases. Great Lakes faces several key challenges. (1) Considerable uncertainty exists with the ongoing restructuring of the electricity industry in Ontario. Power generation will become subject to market forces and the approved ROE on Great Lakes' Northern Ontario regulated transmission and distribution business has been reduced to 9.88%. (2) Utility operations are non-contiguous and are relatively small compared to other Canadian electric utilities. (3) Investment holdings are relatively illiquid as they are primarily in affiliated, unlisted companies. (4) The business risk of the Company is changing as new non-regulated assets are being added. Earnings growth is expected to continue, above the current $100 million level (DBRS-adjusted), in the near to medium term, and operating cash flows should continue to cover dividend requirements. The Great Lakes' capital investment plan to double operating earnings from its power business by 2005 will be largely financed with project mortgages and operating cash flows.

RATING CONSIDERATIONS

Strengths:

- Diversified earnings base: 62%/38% utility/investments
- Low-cost, largely hydro-based generating facilities
- Long-term, flexible power purchase contract
- Long-term power sales contracts for IPPs
- Growth opportunities: Ontario electricity restructuring
- Growing generating assets in selective markets

Challenges:

- Uncertainty relating to Ontario electricity restructuring
- Illiquid investments in affiliated, unlisted companies
- Utility operations are relatively small
- Earnings sensitive to water levels
- Business risk profile is changing
- Customer concentration risk in utility subsidiary

FINANCIAL INFORMATION

	12 mos. ended	Year ended December 31					
Electric Utility Operations	June 2001	2000	1999	1998	1997	1996	1995
Assets / debt (times)	2.41	2.43	2.57	2.09	2.17	2.06	2.16
EBIT interest coverage* (times)	3.13	3.01	2.96	2.73	2.77	2.94	2.40
Cash flow / capital expenditures (times)	2.12	1.51	0.52	3.93	3.66	2.65	2.55
Investment operations							
Assets / debt (times)	1.73	1.72	1.73	2.00	2.04	1.89	2.01
EBIT interest coverage* (times)	1.57	1.60	1.85	1.83	2.09	1.84	1.92
Consolidated results							
Electric utility income ($ millions)	65.1	60.4	53.2	47.7	50.5	51.3	34.6
Investment income ($ millions)	35.8	37.5	44.0	40.3	56.2	44.6	53.8
Consolidated net income ($ millions) (1)	100.9	97.9	97.2	88.0	106.7	95.9	88.4
Operating cash flow ($ millions) (1)	100.6	107.9	115.6	111.0	113.9	109.2	100.6
% debt in capital structure	42.5%	42.2%	41.2%	38.4%	36.6%	39.2%	37.4%
Cash flow / total debt	0.10	0.11	0.13	0.14	0.15	0.13	0.14
Cash flow-divd. / capital expenditures (2)	1.07	0.92	0.30	2.36	(0.33)	0.22	0.38
EBIT interest coverage * (times)	2.23	2.04	2.23	2.13	2.34	2.21	2.07

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

COMPANY

Great Lakes Power Inc. consists of: (1) Energy: Integrated hydroelectric power generation, transmission, and distribution system in northern Ontario, ownership interest in five other hydroelectric operations in Ontario, Quebec, British Columbia and the southern U.S., a natural gas cogeneration plant in northern Ontario, and coal properties that supply thermal power plants in Alberta; and (2) a $1.5 billion investment portfolio (about 61% of total assets) with substantial holdings in affiliated companies. Great Lakes Power Inc. is a wholly owned subsidiary of Brascan Corporation.

Rating Considerations

Strengths: (1) *Diversified earnings base: 62%/38% utility/investments.* Great Lakes' earnings base is comprised of almost two-thirds electric utility earnings and one-third dividend income from an investment portfolio. Investment earnings are a meaningful source of income and are generated from a high proportion of tax-exempt preferred share holdings in affiliated Brascan companies. Consolidated balance sheet strength is acceptable given the structure of the Company. Electric power assets-to associated-debt ratio has consistently remained above two times, and generally has a higher equity component than other Canadian regulated utilities. Securities and corporate investments in preferred shares of affiliated Brascan companies exceed related debt by 1.7 times.

(2) *Low-cost, largely hydro-based generating facilities.* Almost 90% of Great Lakes 987 MW of generating capacity is low-cost hydro-based facilities. In addition, Great Lakes is able to manage its water storage capacity to sell power to other markets during higher peak rate periods.

(3) *Long-term, flexible power purchase contract*. Northern Ontario Power System (NOPS) has a flexible power purchase contract with Ontario Power Generation (OPG). Thus, NOPS can respond quickly to changes in demand. Should demand decline, NOPS is able to reduce purchases of high-priced power from its most costly source first.

(4) *Long-term power sales contracts for IPPs.* All of the independent power plants have long-term power sales contracts for most of their respective outputs. NOPS has a long-term (ten-year) power sales contract for roughly 50% of its output. Long-term contracts allow Great Lakes to lock in margins and minimize price risk.

(5) *Electric industry restructuring in Ontario* could provide opportunities to grow the Ontario-based electric utility assets via acquisitions, as OPG must: (a) reduce its generating capacity by 4000 MW within 42 months of market opening, and (b) further reduce its generating capacity to 35% of available supply in Ontario by November 2010. In addition, there is considerable potential for capacity expansions and/or new generating facilities in Ontario, which could enhance future earnings growth.

(6) *The Company is steadily growing generation in selective markets.* Projects under construction include: (1) High Falls, a $75 million, 45 MW hydroelectric plant in northern Ontario to be completed in Q4 2002; (2) Pingston Creek (50/50 joint venture), a $45 million, 30 MW hydroelectric station in B.C. to be completed in mid-2002; and (3) five hydroelectric plants in southern Brazil (totalling 81 MW), an area with growing demand for power.

Challenges: (1) *Uncertainty relating to Ontario electricity restructuring.* Electric industry restructuring in Ontario will introduce competition. (a) Power generation will become fully subject to market forces, which are expected to intensify as OPG divests assets to reduce its market power. (b) Transmission and distribution will be regulated by the Ontario Energy Board (OEB), and the approved ROE, set at 9.88% is in line with other regulated utilities. However, the earnings impact will depend on the earnings from its unregulated generation business and should not be significant as Great Lakes' transmission and distribution operations are relatively small compared to its power generating operations.

(2) *Illiquid investments in affiliated, unlisted companies.* Investment holdings, about 61% of consolidated assets, are relatively illiquid as they are concentrated in an affiliated, unlisted Brascan group of companies.

(3) *Electric utility operations are relatively small* and service non-contiguous regions in northern Ontario, western Québec and Louisiana, U.S. Electricity sales growth in most of these service regions has been relatively slow. Great Lakes is however, the largest investor-owned utility in Canada

(4) *Earnings sensitive to water levels, negligible marginal profit on purchased power.* Due to the hydro-based nature of its generating facilities, earnings are sensitive to precipitation and water levels in Ontario. NOPS purchases between 30%-40% of its power from OPG. Earnings on purchased power is negligible as the power cost is essentially a "pass-through," earnings are achieved only on the transmission and distribution.

(5) *Customer concentration risk in utility subsidiary*. NOPS' demand load remains heavily dependent on three key customers, which accounted for 84% of NOPS' demand. Also two customers operate in highly cyclical industries - Algoma Steel (36% of power sales) and St. Mary's Paper (19% of power sales). NOPS has a long-term contract with the City of Sault Ste. Marie for 31% of its power. Great Lakes has indicated that the annual power sold to Algoma (approximately 700 GWh) is roughly equivalent to what NOPS purchases annually, thus losing a customer such as Algoma would have minimal impact on the Company's earnings because of the low margins earned on purchased power.

Regulation of Utility Business

Ontario-based power operations are subject to regulation by the NEB and OEB. Historically, Great Lakes operated under a relatively favourable regulatory environment (under the former Ontario Hydro), with earnings based on a 12.08% allowable ROE since 1995. However, the allowable ROE has been set at 9.88% for all regulated transmission and distribution businesses in the province by the OEB. Electricity market restructuring in Ontario, with market opening originally scheduled for November 2000 and delayed to May 2002, will introduce competition, with generation subject to market forces and transmission and distribution regulated by the OEB. Upon market opening, all customers in Ontario will be able to choose their supplier creating opportunities for Great Lakes to benefit from its low cost hydro-based generation in Northern Ontario.

UTILITY PROPERTIES

(As at June 30, 2001)	Location	Gross Installed Capacity (Mw)	% Interest	Owned Capacity – Net (Mw)
Hydroelectric Power				
Northern Ontario Power System	Northern Ontario	327	100%	327
Valerie Falls Power	Northwestern Ontario	10	65%	6.5
Pontiac Power	Western Québec	28	100%	28
Maclaren Energy	Western Quebec	238	50% *	119
Powell River	British Columbia	82	25%*	20.5
Louisiana HydroElectric Power	Louisiana, U.S.	192	75% ^	144
Other operations				
Lake Superior Power (gas cogen plant)	Ontario	110	50%	55
Highvale Power (coal properties)	Central Alberta	0	100%	0
		987		700

* Great Lakes holds a 50% interest in Great Lakes Hydro Income Fund, which owns Maclaren Energy & Powell River.
^ Residual interest.

Currently, over 90% of Great Lakes' generating capacity is low-cost hydro-based and continues to increase. In May 2000, the Company increased its interest in Great Lakes Hydro Income Fund from 40% to 50% for $22 million (the remaining 50% interest is held by the public). In February 2001, Great Lakes Hydro Income Fund acquired a 50% economic interest in the 82 MW Powell River hydroelectric generating stations and related transmission facilities located in the City of Powell River, BC for consideration of $56.5 million and assumption of a future income tax liability. The Company has also developed a new energy marketing business in 2000, which is conducted through Maclaren Energy. In October 2001, Great Lakes announced a $US156.5 million (approximately Cdn$240) agreement to purchase six hydroelectric generating stations, with a capacity of approximately 130 MW, and related transmission assets in northern Maine, the deal is expected to close in early 2002. The Company also has two additional hydro projects under construction in Canada totalling 75 MW, and five hydro-projects in various stages of development in Brazil (total capacity of 81 MW).

FINANCIAL INVESTMENTS

I. Securities Portfolio

($ millions)	June 30, 2001	%	As at Dec. 2000	1999	1998*	1997	1996
Natural resources	150.2	21.0%	147.7	188.8	189	148	148
Real estate	270.5	37.7%	220.5	170.5	96	96	96
Financial services	21.0	2.9%	21.0	21.0	71	81	81
Diversified *	189.4	26.4%	189.4	189.4	212	166	166
Short-term deposits and other	86.0	12.0%	82.7	76.4	84	216	229
Total securities portfolio	717.1	100%	661.3	646.1	652	707	720

* Restated 1998 to reflect new classification.

The securities portfolio consists of tax exempt preferred shares and common shares in the various Brascan (A (low), Pfd-2 (low)) affiliates: natural resource investments include Noranda Inc. (BBB (high)) and Nexfor Inc. (BBB, Pfd-3), financial services holdings are in Trilon Financial Corporation (A (low), Pfd-2 (low)), while real estate securities are in Brookfield Properties Corporation (BBB (high)).

II. Long-term Investments

($ millions) (Ratings1)	June 30, 2001	%	As at Dec. 2000	1999	1998	1997	1996
Trilon Holdings Inc. (pref (A-low))	195.3	37.1%	195.3	195.3	195.3	195.3	195.3
Noranda Equities Inc. (pref (BBB))	150.0	28.5%	150.0	150.0	150.0	150.0	150.0
Brascan Holdings Inc. (pref (BBB-high))	112.0	21.3%	112.0	112.0	112.0	112.0	112.0
Brascan Ltd. – common2	-	-	-	-	-	-	154.0
First toronto investments – common	95.0	18.1%	95.0	95.0	95.0	100.0	120.0
Provisions, accrued interest and other	(26.3)	Nmf	(16.1)	(17.4)	13.0	37.0	37.0
Total long-term investments	526.0		536.2	534.9	565.3	594.3	768.3

1. Ratings reflect junior debt rating of primary operating entities rated by DBRS, i.e., Trilon Financial Corporation, Noranda Inc., and Brascan Corporation.
2. Great Lakes sold its Brascan common shares during 1997, generating an after-tax gain of $12.5 million.

The long-term investment portfolio currently consists primarily of fixed and variable coupon preferred shares that provide stable and attractive after-tax returns. Holdings are almost entirely in the affiliated Brascan group of companies, whose credit ratings (for junior debt) range from BBB to A (low). Although the investments are relatively illiquid, DBRS expects support from Brascan to provide a market. Thus, lack of liquidity should not be a problem.

INCOME FROM UTILITY OPERATIONS

Utility Operations	Current Ownership	12 mos. June 2001	Six months ended June 2001	Six months ended June 2000	For years ended December 31 2000	1999	1998	1997	1996
Northern Ontario Power	100%	123.9	63.2	63.0	123.7	125.4	127.0	124.3	122.7
Lake Superior Power	50%	37.3	19.3	12.4	30.4	23.6	24.6	26.7	27.0
Louisiana HydroElectric Power	75%	11.6	12.4	6.9	6.1	14.4	20.4	14.3	10.6
Pontiac Power	100%	12.4	7.0	7.9	13.3	12.3	10.1	11.1	-
Valerie Falls Power	65%	3.8	1.9	1.6	3.5	3.4	1.3	2.9	3.6
Energy Marketing (1)	50%	14.3	13.0	13.9	15.2	-	-	-	-
Maclaren Energy (1)	50%	31.2	9.2	5.1	27.1	1.1	-	-	-
Highvale Power	100%	7.5	3.8	3.8	7.5	7.5	7.5	7.5	3.8
Revenues		242.0	129.8	114.6	226.8	187.7	190.9	186.8	167.7
Purchased power + fuel costs		80.9	41.7	30.6	69.8	54.1	66.6	58.4	42.1
Operating + maintenance cost		29.7	14.2	11.3	26.8	19.2	17.3	20.3	21.9
Depreciation		21.4	11.0	10.3	20.7	16.7	16.6	15.3	13.3
Municipal/property taxes		14.6	5.7	10.2	19.1	17.4	15.2	12.5	11.4
Operating income		95.4	57.2	52.2	90.4	80.3	75.2	80.3	79.0
Interest expense		30.5	15.3	14.8	30.0	27.1	27.5	29.0	26.9
Capitalized interest/AFUDC		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Net interest expense		30.5	15.3	14.8	30.0	27.1	27.5	29.0	26.9
Income before minority interest		64.9	41.9	37.4	60.4	53.2	47.7	51.3	52.1
Minority interest		(0.2)	0.0	0.2	0.0	0.0	0.0	0.8	0.8
Net income		65.1	41.9	37.2	60.4	53.2	47.7	50.5	51.3
Installed capacity (Mw) (2)		700.0	700.0	679.5	679.5	649.7	498.8	487.5	485.5
Electricity sales (millions of kWh) (2)		3,454.5	1,844.0	1,761.6	3,372.2	3,582.2	3,478.9	3,453.3	3,201.2
Assets/debt (times)		2.41	2.41	2.43	2.43	2.57	2.09	2.17	2.06
Interest coverage (times) (3)		3.13	3.74	3.52	3.01	2.96	2.73	2.77	2.94

(1) Income fund ownership interest increased from 40% in May 2000 (2) Includes ownership interest only. (3) Includes equity income, capitalized interest/AFUD

Utility earnings were up 13.5% to $60.4 million in 2000, primarily as a result of: (1) the first full-year of operations of Maclaren Energy (50% share of power sales and 100% of marketing gains), and (2) a 29% increase in revenues from Lake Superior Power from the resale of contracted gas purchases to take advantage of higher natural gas prices. The increase was partially offset by a 58% drop in revenues from Louisiana Power due to abnormally dry conditions in the U.S. Midwest, and a slight decrease in revenue from Northern Ontario Power due to lower precipitation levels (leading to more expensive energy purchases) and lower power sales to one of the system's large industrial customers. For the six months ended June 2001, net income was 12.6% higher than the same period in 2000 as a result of: (1) higher revenues from Louisiana as power generation returned to normal levels; (2) increased revenue from Lake Superior Power resulting from higher prices for contracted gas purchases; and (3) improved revenues from Maclaren Energy's energy marketing.

Under Ontario electric industry restructuring, NOPS will earn revenue from "wheeling" power through its transmission grid and strategically use its water storage capabilities to maximize power sales during higher-priced peak rate periods.

INCOME FROM INVESTMENTS

Investments & Securities	12 mos. ended June 2001	Six months ended June 2001	Six months ended June 2000	For years ended December 31 2000	1999	1998	1997	1996
Securities portfolio	717.1	717.1	684.0	661.3	646.1	651.9	707.5	719.8
Loans + accts receivables	290.1	290.1	295.0	322.0	325.1	285.7	205.3	153.0
Long-term corporate investments	526.0	526.0	505.3	536.2	504.9	565.4	594.4	767.7
Total Assets	1,533.2	1,533.2	1,484.3	1,519.5	1,476.1	1,503.0	1,507.2	1,640.5
Bank debt + payables	73.0	73.0	59.0	76.4	59.4	49.1	66.3	213.0
Convertible debentures	247.7	247.7	247.7	247.7	247.7	247.7	247.7	247.7
Term notes	566.3	566.3	555.0	558.8	543.8	456.0	426.0	408.0
Total debt	887.0	887.0	861.7	882.9	850.9	752.8	740.0	868.7
Segmented Income								
Corporate investments	47.8	23.0	23.2	48.0	47.4	48.0	47.9	42.9
Securities Portfolio	57.2	26.5	28.0	58.7	51.2	53.1	57.0	57.4
Subtotal	105.0	49.5	51.2	106.7	98.6	101.1	104.9	100.3
Interest (1)	67.0	32.5	32.3	66.8	53.2	55.1	50.1	54.4
Pre-tax income	38.0	17.0	18.9	39.9	45.4	46.0	54.8	45.9
Minority interest	5.2	2.3	1.7	4.6	3.7	5.7	4.2	6.9
Income taxes	(3.0)	(3.0)	(2.2)	(2.2)	(2.3)	0.0	6.9	7.4
Income before extraordinary items	35.8	17.7	19.4	37.5	44.0	40.3	43.7	31.6
Non-recurring items	0.0	0.0	0.0	0.0	0.0	0.0	12.5	13.0
Net income	35.8	17.7	19.4	37.5	44.0	40.3	56.2	44.6
Assets/debt (times)	1.73	1.73	1.72	1.72	1.73	2.00	2.04	1.89
Interest coverage (times)	1.57	1.52	1.58	1.60	1.85	1.83	2.09	1.84

(1) Includes equity income. Financing costs consist of interest expense associated with convertible debentures.

INCOME FROM INVESTMENTS – CONT'D

Total investment assets have been relatively stable around $1.5 billion over the past three years. Assets and debt levels and have risen slightly year-over-year such that the assets-to-debt ratio has remained at 1.7 times in 2000. Earnings from investments decreased by 15% primarily due to higher interest costs associated with the acquisition of Maclaren Energy. Investment earnings year-to-date at June 2001 declined from the same period last year as a result of lower average interest rates.

CONSOLIDATED EARNINGS

	12 mos. ended	Six months ended		For years ended December 31				
	June 2001	June 2001	June 2000	2000	1999	1998	1997	1996
Revenues - utility operations	242.0	129.8	114.6	226.8	187.7	190.9	186.8	167.7
- Fee Income	47.8	23.0	23.2	48.0	47.4	48.0	47.9	42.9
- Investment Income	57.2	26.5	28.0	58.7	51.2	53.1	57.0	57.4
Total revenues	347.0	179.2	165.7	333.5	286.3	292.0	291.7	268.0
Operating income	200.4	106.6	103.3	197.1	178.9	176.3	185.2	179.3
Net income (before extras.) (1)	100.9	59.5	56.5	97.9	97.2	88.0	94.2	82.9
Net income (1)	100.9	59.5	56.5	97.9	97.2	88.0	106.7	95.9
Income - % breakdown								
Utility	64.5%	70.3%	65.8%	61.7%	54.7%	54.2%	47.3%	53.5%
Investments	35.5%	29.7%	34.2%	38.3%	45.3%	45.8%	52.7%	46.5%
Assets - % breakdown								
Utility	39.6%	39.6%	39.3%	38.6%	37.6%	33.3%	32.6%	30.1%
Investments	60.4%	60.4%	60.7%	61.4%	62.4%	66.7%	67.4%	69.9%

(1) Adjusted to include interest expense on convertible debentures.

The 2000 consolidated earnings remained at the same level as 1999, and earnings for the six months ended June 2001 are basically flat with the same period last year. Although utility assets represented only 38.6% of total assets, it contributed a strong 61.7% of total income in 2000. Utility contributions have increased to 70.3% of total income for the six months ending June 30, 2001, as revenues from its generation facilities and gas sales improved.

Outlook: Earnings are expected to be near $100 million in 2001. Earnings growth is expected to continue into the near future through acquisitions, new construction and improvement in operating efficiencies. However, earnings will be influenced by the following factors: (1) growing competition in generation as the Ontario electricity industry restructures; (2) a reduction in allowable ROE on regulated transmission and distribution partially offset by higher generation revenues; and (3) a decrease in natural gas prices, to long-term average levels, will limit Great Lakes' ability to resell Lake Superior Power contracted gas.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

Cash Flow Statement	12 mos./Jun.30	Year ended December 31				**Stress Testing** (1)		
($ millions)	2001	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	221.8	217.8	195.6	192.9	200.5	217.3	235.0	235.0
Net income (before extras.)	100.9	97.9	97.2	88.0	94.2	88.5	83.7	76.9
Depreciation & amortization	21.4	20.7	16.7	16.6	15.3	20.7	26.2	27.7
Other non-cash adjustments	(21.7)	(10.7)	1.7	6.4	4.4	0.0	0.0	0.0
Cash flow from operations	100.6	107.9	115.6	111.0	113.9	109.2	109.9	104.6
Dividends paid (received)	64.9	64.9	64.9	64.9	64.9	65.0	65.0	65.0
Capital expenditures	37.5	52.7	139.0	18.4	18.0	290.0	100.0	100.0
Cash flow before working capital	(1.8)	(9.7)	(88.3)	27.7	31.0	(245.8)	(55.1)	(60.4)
Change in working capital	16.8	(10.9)	(17.1)	(22.4)	126.5	0.0	0.0	0.0
Gross free cash flow	(18.6)	1.2	(71.2)	50.1	(95.5)	(245.8)	(55.1)	(60.4)
Investments & other	4.1	6.2	(31.3)	(1.1)	167.4	0.0	0.0	0.0
Net free cash flow	(14.5)	7.4	(102.5)	49.0	71.9	(245.8)	(55.1)	(60.4)
Change in debt: new/(repayments)	18.0	(6.9)	102.5	(49.0)	(71.9)	245.8	55.1	60.4
Change in net cash	3.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Key Figures and Ratios:								
Total debt in capital structure	983.6	952.3	890.0	816.0	762.4	1,198.1	1,253.3	1,313.7
% debt in capital structure	42.5%	42.2%	41.2%	38.4%	36.6%	47.4%	48.2%	49.1%
EBITDA interest coverage (times)	2.46	2.25	2.44	2.34	2.53	2.15	1.98	1.90
EBIT interest coverage (times)	2.23	2.04	2.23	2.13	2.34	1.94	1.76	1.67
Cash flow/ total debt	0.10	0.11	0.13	0.14	0.15	0.09	0.09	0.08
Stress Test Assumptions:								
EBITDA growth						-10%	0%	0%
Interest rate (based on exisiting blended rate)						9.9%	9.9%	9.9%

Financial Profile: While operating cash flows decreased by 6.7% in 2000 to $107.9 million, gross free cash flow improved to $1.2 million from ($71.2) million in 1999, primarily as a result of a decrease in capital expenditures to $52.7 million from $139.0 million. With the exception of 1993, 1999 and 2000, the Company has historically been able to fund its capital expenditures and dividend payments with free cash flow. Higher capital expenditures over the last two years have resulted in higher debt levels and weaker debt ratios, which remain at acceptable levels. (Note: DBRS treats the convertible debentures as an equity equivalent, given that the Company has the option to repay interest and principal with common shares.)

Outlook: Consolidated cash flow from operations is expected to improve in the near term, reflecting earnings contributions from recent acquisitions and the return to more normal water levels in the U.S. Midwest.

In November 2000, Great Lakes announced a $500 million capital investment program with the objective of doubling operating earnings from its power business by 2005. In October 2001, Great Lakes purchased six hydroelectric stations and related transmission assets in Maine for US$156.5. This will weaken debt ratios, however will strengthen cash flows. The Company has the capacity to carry this level of debt.

Sensitivity Analysis:

(1) DBRS stress test the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Company, nor DBRS expectations concerning the future performance of the Company.

The following scenario was assumed: (1) EBITDA decreases by 10% in Year 1 and remains constant thereafter, (2) capital expenditures are $290 million in Year 1 (representing $240 for the Maine acquisition and $50 million for other) and $100 million in Years 2 and 3, (3) 50% of earnings contribution from the Maine acquisition will occur in Year 1 and the full amount (approximately $35 million before interest) will occur in remaining years, and (4) any free cash flow deficit is debt financed.

Under this scenario, Great Lakes would require about $350 million in new debt over three years, but should be within the capacity of the Company to carry. Debt levels near 50% appear workable.

Operating Lines of Credit

Great Lakes has a $118 million, 18-month revolving bank facility that supports a commercial paper program. Additionally, Great Lakes has a US$100 million loan facility with its parent Brascan, secured by Great Lakes' residual interest in its Louisiana HydroElectric Power investment. The facility can be drawn down by either party and converted into a fixed rate bank loan, repayable in 2015.

Debt Maturity Schedule (at Dec. 31, 2000)	2001	2002	2003	2004	2005
Long-term debt ($ millions)	110.3	5.8	161.8	5.0	29.5

In April 2000, Great Lakes Hydro Income Fund issued 3 First Mortgage Bonds of $50 million with interest rates of 7.33%, 7.55%, and 7.78% which are due April 2005, April 2010, and April 2015, respectively.

Balance Sheet

($ millions)	June 30	As at December 31			June 30	As at December 31	
Assets	2001	2000	1999	**Liabilities & Equity**	2001	1999	1999
Securities portfolio	684	661	646	Bank borrowings	0	0	0
Loans + accts. receivable	295	322	325	Accts pay. + accr'ds	59	76	59
Coporate investments: Trilon Holdings-pfd	195	195	195	Current liabilities	59	76	59
Brascan Holdings - pfd	112	112	112	Def'd credits	104	104	107
First Toronto - common	0	0	0	Minority interest	93	94	93
Noranda Equities - pfd	150	150	150	Term notes	555	559	544
Other	48	79	48	Project debt	396	394	346
Net fixed assets	963	957	889	Convertible debt	210	210	210
				Common equity	992	1,001	968
Total	2,447	2,476	2,365	Total	2,410	2,439	2,328

	12 mos. ended	For years ended December 31						
Ratio Analysis (1)	June 2001	2000	1999	1998	1997	1996	1995	1994
Return on common equity (after extras. gains)	8.3%	8.2%	8.1%	7.3%	9.2%	8.7%	8.3%	10.9%
Dividend payout ratio	64.3%	66.3%	66.8%	73.8%	60.8%	63.8%	68.1%	63.7%
% debt in the capital structure	42.5%	42.2%	41.2%	38.4%	36.6%	39.2%	37.4%	47.1%
Net debt in the capital structure (2)	16.7%	18.2%	16.1%	11.2%	4.0%	8.2%	1.7%	19.4%
EBIT interest coverage (3)	2.23	2.04	2.23	2.13	2.34	2.21	2.07	2.62
EBITDA interest coverage (3)	2.46	2.25	2.44	2.34	2.53	2.37	2.23	2.81
Cash flow/total debt	0.10	0.11	0.13	0.14	0.15	0.13	0.14	0.13
Cash flow/capital expenditures (4)	3.01	2.32	0.68	5.69	(0.76)	0.51	0.94	1.25
Cash flow-dividend/capital expenditures (4)	1.07	0.92	0.30	2.36	(0.33)	0.22	0.38	0.62

Hydro One Inc.

(Formerly Ontario Hydro Services Company Inc.)

Current Report: February 28, 2001
Previous Report: September 6, 2000

RATING

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Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Senior Unsecured Debentures

RATING HISTORY (as at Dec. 31)	Current	2000	1999	1998	1997
Senior Unsecured Debentures	"A"	"A"	N/R	N/R	N/R

RATING UPDATE

DBRS is confirming the long-term debt rating of Hydro One Inc. ("Hydro One" or "the Company") at "A" with a Stable trend, based on the following considerations. (1) Recently announced cuts to distribution rates effective with the market opening should be partially offset by an expected improvement in operating efficiencies over the longer term as a result of internal rationalizations and the acquisition of 87 municipal electric utilities (MEUs). (2) Both the Company's commitment to maintaining key debts ratios at levels reflective of current credit ratings and the fact that the bulk of earnings and cash flows will continue to be generated from regulated transmission and distribution assets should contribute to relative financial stability. While the MEU acquisitions will weaken key debt ratios by the end of 2001, ratios are expected to remain at acceptable levels. (3) The earnings growth outlook over the longer term remains favourable as there are still acquisition opportunities, with numerous smaller MEUs within Hydro One's rural network that may find it difficult to operate on a stand-alone basis once the market opens. In addition, earnings should benefit from the development of the Company's fibre-optic network business and expansion into energy marketing. Over the near term, the Company will have to contend with a number of challenges that could adversely affect earnings and cash flows. The negative experience California and Alberta have had with deregulation will likely further delay the market opening while the provincial government ensures that conditions are conducive to a successful implementation. This should have a positive impact on earnings over the short term, but retail competition, when it is implemented, will expose the Company's energy marketing business to potential commodity pricing risks and earnings pressures. In addition, DBRS expects the Ontario electricity distribution industry will be faced with some uncertainty over the next few years as the highly fragmented industry continues to consolidate.

RATING CONSIDERATIONS

Strengths:

- Regulation contributes to earnings/financial stability
- Attractive Ontario-based business franchise
- Internal rationalization/acquisitions should contribute to an improvement in future operating efficiencies
- Opportunities for growth of distribution business

Challenges:

- Retail competition: potential commodity pricing risks
- Uncertainty: industry consolidation/deregulation
- Capital expenditures maintenance backlog
- Heavy debt refinancing schedule
- Lack of access to public equity markets

FINANCIAL INFORMATION

	Industry Avg.*	For years ended December 31 (1)				
	Sep-00	2000	1999	1998	1997	1996
Fixed Charges Coverage (times)	*2.14*	2.30	2.32	1.46	1.50	1.64
% Adjusted Debt in the Capital Structure (2)	*59.7%*	54.2%	54.6%	71.8%	75.0%	75.9%
Cash Flow/Adjusted Total Debt (times)(2)	*0.14*	0.15	0.15	0.09	0.09	0.11
Cash Flow/Capital Expenditures (times)	*1.17*	1.58	1.34	1.43	1.86	2.23
Approved ROE	-	9.88%	9.35%	-	-	-
Operating Income ($ millions) (before extras.)	-	930	997	829	888	973
Net Income ($ millions) (bef extras. after pfd.)	-	381	422	270	304	383
Operating Cash Flow ($ millions)	-	684	722	546	538	673
Electricity Sold - Distribution (GWh)	-	17,600	18,100	18,300	18,800	18,600

(1) 1999: nine months. Hydro One + 3-mos. allocation of Ontario Hydro results. 1996-8: an allocation of Ontario Hydro results that reflect the operations of Hydro One. (2) Adjusted for equity treatment of hybrid debt securities. *DBRS composite for Canadian gas and electricity distributors.

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 rural 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 wholly owned by the Province of Ontario. Debt issued directly by Hydro One Inc. is not guaranteed by the province.

REGULATION

Hydro One's distribution and transmission subsidiary (Hydro One Networks) is regulated by the Ontario Energy Board (OEB) based on a cost of service/rate of return methodology. Deemed common equity has been set at 35%. The 2000 approved ROE of 9.88% remains unchanged, exclusive of the impact of the MEU acquisitions which may also be subject to a phasing in of the market rate of return like other local distribution companies (LDC) in Ontario.

Distribution rate adjustments for the next two years (2002-2003) will likely be based on a price cap performance-based regulatory (PBR) mechanism. Adjustments in the second and third years will take into account (a) an inflation factor (the change in the cost of inputs for a *typical* utility), less (b) a *benchmark* productivity factor (cost of service reductions as a result of achieved operating efficiencies), plus (c) a factor to address extraordinary events that affect the cost of service. This would include certain transition costs to separate "wires" and energy retailing operations, and expenses to prepare for the new competitive environment. Incorporation and business re-organization costs related to the development of energy marketing operations are to be borne by the shareholder and cannot be passed through to rate payers. Acquisition premiums (of other MEUs) cannot be passed through to ratepayers although revenue-neutral rate harmonizations may be permitted. Transmission is not currently regulated under PBR. The *transmission rate setting* methodology that will be applicable in the future has yet to be determined.

The price cap mechanism operates as a price ceiling. LDC's whose input costs increase more than the *typical* utility (i.e., a composite of 48 Ontario LDCs) and/or whose productivity gains are less than the *benchmark* (i.e., based on a composite 48 Ontario LDCs) will experience an earnings reduction. However, LDCs who exceed these defined targets are permitted to retain all of the "excess" earnings. Overall, DBRS views PBR mechanisms favourably as they encourage operating efficiencies and reduce a utility's regulatory burden over the longer term. The next generation PBR mechanism is expected to consist of a "yardstick" approach where utilities may be measured against peer groups (i.e., based on similar characteristics such as size, customers and geographic location) rather than a *typical benchmark*.

RATING CONSIDERATIONS

Strengths: (1) *Cost of service regulation contributes to relative earnings and financial stability* - The recent implementation of a PBR mechanism and the use of formula- based ROEs minimizes the related cost burden and contributes to financial stability. PBR minimizes regulatory lag, streamlines the regulatory process, and encourages utilities to improve operating efficiencies.

(2) *Attractive business franchise* - Hydro One's franchise area is among the fastest growing in Canada. Transmission operations cover virtually all of Ontario. The distribution/retail franchise is less attractive as it includes a large geographic area (basically most of rural Ontario outside major urban centres) with a low population density/high cost of service. The relatively high cost of retail distribution services (to rural customers) makes the region less attractive to competitors.

(3) *Internal rationalization improving operating efficiencies* - The process began with a voluntary retirement program that resulted in a reduction of 1,402 employees by the end of 2000. Union concessions that will allow for an increase in the use of seasonal hirings and the bundling of the transmission and distribution work force should also contribute to a reduction in labour costs. Other productivity initiatives currently under way include the consolidation of field offices, service vehicles and fleet maintenance centres, inventory sites and material levels.

(4) *Opportunities for growth in distribution segment* - There were 214 small MEUs within Hydro One's rural distribution franchise network, many of which were too small and fragmented to be efficient. Hydro One rationalized many of them during 2000 and about 59 remain independent. The integration of these acquisitions will enhance operating efficiencies and spread fixed costs over a large asset/customer base. The recent acquisition of 87 MEUs, 80 of which require regulatory approval, will increase the customer base by 25%, electricity (distribution) throughputs by 40% (GWh) and the distribution infrastructure network by 6% (km).

Challenges: (1) *Retail competition will create earnings pressures* - Ontario LDC's are required to separate the distribution wires (regulated) operations from non-regulated businesses effective with the market opening. The provincial government delayed the market opening (initially scheduled for November 2000), but when it is implemented (possibly as early as the fall of 2001), Hydro One's retail energy marketing business will be exposed to commodity price risks and competitive pressures.

(2) *Uncertainty during transition period* - These uncertainties stem from two sources: (a) The Ontario electricity distribution industry remains highly fragmented, with 92 MEUs (assuming all mergers and acquisitions filed with the OEB as of November 2000 are approved) compared to two private sector gas distributors. DBRS expects that there will be further significant rationalization over the next few years as the industry continues to consolidate. (b) The transition towards operating as a commercially viable enterprise will require a significant change in culture and will likely take some time to fully implement.

(3) *"Catch-up" capital expenditures required* - Given the deferral of asset maintenance by the former Ontario Hydro, Hydro One's ongoing capital expenditures will include a required maintenance backlog. In addition, the integration of numerous acquired MEUs will likely involve expenditures to harmonize systems and procedures as well as the condition of capital assets.

(4) *Relatively heavy debt refinancing schedule* - Although debt maturities are reasonable well staggered, Hydro One

needs to refinance between $450 million - $680 million annually over the next five years.

(5) *Lack of access to public equity markets* - DBRS expects the distribution and transmission operating subsidiaries will maintain debt-to-capital within regulatory limits (35% deemed equity). However, Hydro One is a holding company and will likely use additional leverage to finance acquisitions and other investments. DBRS does not expect the province to make any further equity injections. Key debt ratios and balance sheet strength would come under pressure if internally generated cash flows are insufficient to finance growth and/or address funding requirements.

EARNINGS

Segmented Information		For years ended December 31 (1)				
($ millions)	%	2000	1999	1998	1997	1996
Transmission	59%	1,260	1,237	1,178	1,095	1,112
Net Distribution (incl. retail)	39%	837	854	564	596	662
Other	2%	32	95	141	158	137
Net revenues		2,129	2,186	1,883	1,849	1,911
Transmission	68%	631	641	621	625	636
Distribution (incl. retail)	34%	318	368	202	281	335
Other	-2%	(19)	(13)	6	(18)	2
Operating income (EBIT)		930	997	829	888	973
Net interest expense		340	381	559	584	590
Payments in lieu of income taxes		209	194	0	0	0
Net income before extras. + pfd div's		381	422	270	304	383
Extraordinary items		3	47	(204)	79	0
Net income after extras.		378	375	474	225	383
Preferred dividends (declared)		18	14	0	0	0
Net income available to common shldrs		360	362	474	225	383
Transmission	65%	6,492	6,658	6,107	6,001	5,924
Distribution (incl retail)	34%	3,434	3,377	3,168	2,892	2,911
Other	1%	71	55	160	166	167
Total Assets ($ millions)		9,997	10,090	9,435	9,059	9,002
Distribution Throughputs						
Residential		9,240	9,412	9,882	10,152	10,044
Commercial		3,960	3,982	4,209	4,324	4,278
Industrial		1,760	2,172	1,647	1,692	1,674
Other		2,640	2,534	2,562	2,632	2,604
Total (GWh)		17,600	18,100	18,300	18,800	18,600
Growth in volume throughputs		-2.8%	-1.1%	-2.7%	1.1%	-
Transmission Throughputs (GWh)		146,900	144,100	143,000	144,800	143,000

(1) 1999 consists of 9-mos. Hydro One + 3-mos. allocation of Ontario Hydro results. 1996-8 is an allocation of Ontario Hydro results that reflect the operations of Hydro One operations.

Consolidated EBIT in 2000 fell 6.7% to $930 million from $997 million last year in spite of a 53 basis point increase in the approved ROE. The decline in EBIT was largely attributable to lower distribution earnings. A cooler than normal summer and the statutory annexation of service territories and customers by certain MEUs during 1999 contributed to a 2.8% decrease in retail demand for electricity in 2000.

Net earnings before extraordinary items and preferred dividends were down 9.8% for the year. A full year's impact of PILs (payments in lieu of taxes) more than offset lower financing costs following the equity for debt swap in April 1999 with the Province of Ontario.

Outlook: In spite of the acquisition of 87 MEUs and no change in the approved ROE, net earnings in 2001 are expected to be lower than 2000 due to the following.

- Higher financing costs as 71 of the MEU acquisitions (for a total cost of about $500 million) are expected to close during 2001.
- The acquisition of 87 MEUs, 16 of which closed by December 2000, will likely involve costs to integrate

systems and procedures but should also result in improved operating efficiencies over the longer term.

- Distributions earnings in particular are expected to be weaker upon market opening when Hydro One becomes subject to market-based pricing for power purchases. The Company's notional cost of power (3.8¢ per kWh wholesale rate cap) was initially based on a transitional revenue reallocation among the Ontario Hydro successors companies. To mitigate the impact on earnings Hydro One expects to immediately implement a number of cost control initiatives that should partially neutralize the expected reduction in distribution revenues. The date of the market opening will influence the magnitude of the earnings impact. The market opening, initially set for November 2000, was deferred and a new target date has not been officially set. The negative experience California and Alberta have had with deregulation will likely further delay the market opening in Ontario while the provincial government ensures that conditions are conducive to a successful implementation. Earnings should benefit from the cost control initiatives to the extent that the market opening is delayed beyond the fall of 2001.

The market opening could also adversely affect consolidated earnings as follows:

- While it should be a source of earnings, retail competition will expose Hydro One's energy marketing subsidiary (*Ontario Hydro Energy*) to potential commodity pricing risks. Bilateral supply and power sales contracts could materially reduce this risk and effectively hedging supply requirements will be necessary to maintain consistently positive spreads. Note that this pricing exposure is limited to retail customers only. "Standard supply" or "default supply" customers (i.e., existing customers who do not specifically choose a supplier) will be serviced by *Hydro One Networks*, with all power costs (and no profit margin) passed through to the customer.
- Hydro One currently has a monopoly in its franchise region and retail competition could lead to some customer losses. However, DBRS does not expect competitive pressures to be a significant concern for Hydro One given the nature of its rural-based franchise region (low population density/high cost of service). Energy marketers will likely be more active in the major urban centres at least during the early stages of retail competition. Note that while the acquisition of Brampton Hydro allows Hydro One to participate in higher growth markets, it will also be a region that will likely be subject to greater competitive pressures.

Consolidated earnings beyond 2001 will be subject to competitive pressures and commodity pricing risks (retail energy marketing division only) concurrent with the market opening, but should benefit from productivity initiatives currently underway as well as a full year's contribution from the 71 MEU acquisitions expected to close during the current year. In addition, under the first generation PBR expected to take effect in 2002, future distribution earnings/rate adjustments will be influenced or even determined by a utility's ability to meet defined productivity targets (see Regulation). Based on the proposed model, inefficient operators may experience a relative earnings reduction.

FINANCIAL PROFILE

Operating cash flows fell to $684 million from $722 million last year, in line with weaker earnings (see above). Actual capital expenditures have been scaled back from plan as Hydro One has focused on the acquisition of the MEUs to take advantage of the preferential tax treatment allowed prior to November 2000. As a result, operating cash flows were more than sufficient to address T&D capital expenditures.

Hydro One has drawn down material cash holdings ($468 million as at December 1999 reduced to $0 as at December 2000) to fund dividend payments to the province and debt repayments. As a result, adjusted (for hybrid securities) financial leverage remains relatively stable at 54.2% compared to 54.6% last year. Key debt ratios are currently somewhat stronger than industry averages.

	Hydro One	**DBRS Industry Composite***
Cash flow/Adj. total debt	0.15X	0.14X
Cash flow/Capexp	1.58X	1.17X
Fixed charges coverage	2.30X	2.14X
% Adjusted debt	54.2%	59.7%

* Gas and Electric Distribution Utilities - As at September 2000.

Outlook: Operating cash flows in 2001 may decline depending largely on the date of the market opening (see earnings outlook), but should still be adequate to finance fixed asset capital expenditures in the $450 million range. Hydro One continues to address the maintenance backlog inherited from the former Ontario Hydro, and during 2001-2 will integrate systems and procedures of the acquired MEUs as well as commence construction on a project to increase target intertie capacity 50% (or 2000MW) by 2003. With another 71 MEU acquisitions (for roughly $500 million) expected to close in 2001, key debt ratios (debt-to-capital, fixed-charges coverage and cash flow/total debt) are expected to be weaker by the end of the year but should remain at levels that adequately reflect current credit ratings, and roughly in line with industry composites. Ratios are expected to slowly improve thereafter.

Additional acquisitions and competitive pressures once the market opens could pressure key debt ratios. Hydro One is, however, committed to maintaining financial stability, and key debt ratios should remain near current levels barring a major acquisition.

($ millions)	2000	1999R	1998R	1997	1996
	For years ended December 31 (1)				
Net income (before extras., after pfd.)	363	409	270	304	383
Depreciation	324	324	276	266	273
Other non-cash charges	(3)	(11)	0	(32)	17
Operating Cash Flow	684	722	546	538	673
LESS: Capital expenditures	434	540	383	289	302
Cash flow before working capital changes	250	182	163	249	371
LESS: Working capital changes	(11)	(129)	26	(97)	190
Free cash flow before dividends	261	311	137	346	181
LESS: Common dividends	380	0	0	0	0
Free cash flow after dividends	(119)	311	137	346	181
LESS: Other investments	92	(288)	0	4	(3)
PLUS: Net debt financing	(281)	(170)	(98)	(226)	(149)
PLUS: Net equity financing	0	0	0	0	0
Net change in cash flows	(492)	429	39	116	35
Cash flow/Capital expenditures (times)	1.58	1.34	1.43	1.86	2.23
Cash flow/Adjusted total debt (times)(2)	0.15	0.15	0.09	0.09	0.11
% Adjusted debt in capital structure (2)	54.2%	54.6%	71.8%	75.0%	75.9%
Fixed charges coverage (times)	2.30	2.32	1.46	1.50	1.64

(1) 1999 consists of 9-mos. Hydro One + 3-mos. allocation of Ontario Hydro results. 1996-8 is an allocation of Ontario Hydro results that reflect the operations of Hydro One operations.

(2) Adjusted for equity treatment of hybrid debt securities.

OPERATING LINES OF CREDIT

A $750 million syndicated stand-by (committed) bank line used to backstop commercial paper issuance. This includes a $500 million 364-day line due in 2001 and a $250 million five-year bank line maturing in 2005. Hydro One has the option to increase bank lines to support a Board authorized $1 billion commercial paper borrowing limit.

DEBT MATURITY SCHEDULE

(As at December 2000 - $ millions)

Years to Maturity	Public Debentures	Notes Payable to OEFC	Average Coupon
1 year	-	474	7.20%
2 years	-	443	10.96%
3 years	-	651	7.22%
4 years	-	682	6.78%
5 years	200	307	7.72%
SUB TOTAL	200	2,557	7.80%
6-10 years	400	889	9.07%
Over 10 years	400	-	7.35%
TOTAL	1,000	3,446	8.13%

Hydro One will either refinance in its own name and/or repay notes payable to OEFC as they mature. While the Company has a relatively heavy refinancing schedule over the next five years, debt maturities are reasonably well staggered and the refinancing of high coupon debt issues in 2002 should reduce financing costs. Note that PILs (payments in lieu of income taxes), common dividends as well as a portion of interest expenses is paid directly or indirectly to OEFC to service the outstanding debt of the former Ontario Hydro. The weighted-average coupon on Hydro One's debt portfolio compares favourably with DRBS' gas and electricity distribution industry composite of 8.4%.

Hydro One Inc.

(formerly Ontario Hydro Services Company Inc.)

Balance Sheet (1)

($ millions)	As at December 31				As at December 31		
Assets:	2000	1999R	1998	Liabilities & Equity:	2000	1999R	1998
Cash + short-term investments	0	468	44	Short-term debt	154	0	568
Accounts receivable	511	536	398	L.T.D. debt due 1 year	474	1,399	491
Material and supplies	65	81	65	A/P + accr'ds	421	475	397
Current Assets	576	1,085	507	Current Liabilities	1,049	1,874	1,456
Net fixed assets	8,519	8,359	8,383	Long-term debt	3,972	3,446	5,128
Post employment benefits	452	241	224	Post employ. benefits	509	496	305
Def'd debt costs + long-term rec.	92	22	321	Long-term pay. + other l	467	250	115
Regulatory asset	352	383	0	Conv. preferred equity	323	0	0
Goodwill	6	0	0	Shareholders equity	3,677	4,024	2,431
Total	9,997	10,090	9,435	Total	9,997	10,090	9,435

Ratio Analysis (1)

	Industry Avg.*	For years ended December 31				
Liquidity Ratios	*Sep-00*	2000	1999R	1998R	1997	1996
Current Ratio	*0.90*	0.55	0.58	0.35	0.27	0.41
Accumulated depreciation/Gross fixed assets	*30.5%*	32.5%	31.5%	31.3%	30.4%	29.2%
Cash flow/Total debt (2)	*0.14*	0.15	0.15	0.09	0.09	0.11
Cash flow/Adjusted total debt (2)	*0.14*	0.15	0.15	0.09	0.09	0.11
Cash flow/Capital expenditures	*1.17*	1.58	1.34	1.43	1.86	2.23
Cash flow-dividends/Capital expenditures	*0.57*	0.70	1.34	1.43	1.86	2.23
% Debt in the capital structure (2)	*58.8%*	53.5%	54.6%	71.8%	75.0%	75.9%
% Adjusted debt in the capital structure (2)	*59.7%*	54.2%	54.6%	71.8%	75.0%	75.9%
Average coupon on long-term debt	-	8.13%	7.70%	9.00%	-	-
Hybrids/Common equity	*10.0%*	8.8%	0.0%	0.0%	0.0%	0.0%
Deemed equity	-	35.0%	35.0%	-	-	-
Common dividend payout (before extras.)	*97.9%*	58.7%	38.7%	0.0%	0.0%	0.0%
Coverage Ratios (3)						
EBIT interest coverage	*2.31*	2.50	2.45	1.46	1.50	1.64
EBITDA interest coverage	*3.24*	3.42	3.29	1.98	2.02	2.17
Fixed charges coverage	*2.14*	2.30	2.32	1.46	1.50	1.64
Earnings Quality/Operating Efficiencies & Statistics						
Operating margin	*41.4%*	43.7%	45.6%	44.0%	48.0%	50.9%
Net margin (before extras., after pfd)	*16.8%*	17.0%	18.7%	14.3%	16.4%	20.0%
Return on avg common equity (before extras.)	*10.7%*	9.4%	12.7%	12.0%	14.9%	20.9%
Approved ROE	-	9.88%	9.35%	-	-	-
Rate base (Transmission) (millions)	-	5,707.4	5,637.9	-	-	-
Rate base (Distribution) (millions)	-	2,444.7	2,466.8	-	-	-
Distribution lines (km)	-	113,880	113,400	116,947	119,182	118,985
Transmission lines (km)	-	28,490	28,889	29,066	29,080	29,080
GWh throughputs/Employee	-	36.8	28.8	30.9	31.3	29.5
Customers/Employee	*335*	214	166	187	186	176
Customers/Distribution lines	-	8	8	8	8	8
Growth in customer base	*1.4%*	2.5%	-4.5%	0.5%	1.1%	-
Operating costs/Avg. customer ($) (4)	*468*	983	1,043	850	917	1,010

(1) 1999 consists of 9-mos. Hydro One + 3-mos. allocation of Ontario Hydro results. 1996-8 ratios reflect the allocation of Ontario Hydro results which represent Hydro One operations. (2) Convertible preferred equity given 80% common equity treatment.

(3) EBIT includes interest income, interest expense excludes capitalized interest, AFUDC and debt amortizations .

(4) For distribution operations only. * DBRS industry composite for Canadian gas and electricity distributors.

Hydro One Inc.

(formerly Ontario Hydro Services Company Inc.)

Income Statement	For years ended December 31 (1)				
($ millions)	2000	1999R	1998R	1997	1996
Distribution (incl. retail)	1,703	1,793	1,729	1,846	1,880
Transmission	1,260	1,237	1,178	1,095	1,112
Other	32	95	141	158	137
Gross revenues	2,995	3,125	3,048	3,099	3,129
Purchased power	866	939	1,165	1,250	1,218
Net revenues	2,129	2,186	1,883	1,849	1,911
Expenses:					
OM&A	826	792	723	627	602
Municipal + property taxes	25	47	0	0	0
Debt guarantee fee	0	8	31	32	31
Depreciation + amortization	348	342	300	302	305
Total operating costs	1,199	1,189	1,054	961	938
Operating income	930	997	829	888	973
Interest expense	379	411	569	580	583
Non-cash financial charges	(22)	(18)	(10)	(12)	(8)
Other (income)/expense	(17)	(12)	0	16	15
Net interest costs	340	381	559	584	590
Pre-tax income	590	616	270	304	383
Payments in lieu of income taxes	209	194	0	0	0
Net income bef. extraordinary items	381	422	270	304	383
Extraordinary items	3	47	(204)	79	0
Net income before pfd. div's.	378	375	474	225	383
Preferred dividends (declared)	18	14	0	0	0
Net income	360	362	474	225	383

(1) 1999 consists of 9 months Hydro One and 3 months allocation of Ontario Hydro results. 1996-8 is an allocation of Ontario Hydro results that reflect the operations of Hydro One operations.

APPENDIX - THE RESTRUCTURING OF ONTARIO HYDRO

Under the industry restructuring which became effective April 1, 1999, five separate entities were created from the former Ontario Hydro: (1) Ontario Power Generation Inc. (OPG), which holds and operates all the generating assets; (2) Ontario Hydro Services Company Inc. (now Hydro One Inc.), which holds and operates all the transmission and distribution assets; (3) Ontario Electricity Financial Corporation (OEFC), which is responsible for managing and retiring the outstanding debt and certain other liabilities of the former Ontario Hydro; (4) Independent Electricity Market Operator (IMO), a non-profit corporation that will perform the central market operating functions; (5) Electrical Safety Authority (ESA), a non-profit corporation that will conduct electric installation inspections. The financial restructuring, which primarily involved OPG, OHSC (now Hydro One) and OEFC was effected as follows: The $38.1 billion in outstanding debt and liabilities, (including non-utility generation and past unfunded nuclear liabilities) as at April 1, 1999, of the former Ontario Hydro were assumed by OEFC. These debt obligations will retain the pre-existing government guarantee, and as they mature, they will either be retired or refinanced by OEFC with the government guarantee. The combined value of the successor companies was identified at $17.2 billion. This resulted in stranded debt of $20.9 billion ($38.1 billion - $17.2 billion), to be offset by $13.1 billion in defined (present value) dedicated revenue streams, leaving $7.8 billion in residual stranded debt with no backing assets or cash flow. Step 1 of the process involved a transfer of assets from Ontario Hydro to the various successor companies in exchange for an equal amount of debt. In step 2, the province assumed a portion of OPG and OHSC's (now Hydro One's) debt in exchange for equity. (1) Assets of $8.5 billion were transferred to OPG. The province assumed $5.1 billion of OPG's debt in exchange for equity, leaving that company with a 40%/60% debt-to-equity capital structure. (2) Assets of $8.6 billion were transferred to OHSC (now Hydro One). The province assumed $3.8 billion of OHSC's (now Hydro One) debt in exchange for equity, leaving the Company with a 60%/40% debt-to-equity capital structure. OEFC will service the $20.9 billion in debt and liabilities of the former Ontario Hydro through the following sources: (a) debt service from the successor companies (issued in the assets-for-debt transfer); (b) debt service from the province, which assumed $8.9 billion of debt in the debt-for-equity exchange (which may be repaid through the collection of dividend payments from the successor companies); (c) payments-in-lieu of taxes from the successor companies and the MEUs. These "deemed taxes" are intended to put government entities on an equivalent commercial footing with their private sector counterparts and help pay down the debt; and (d) A Competition Transition Charge (CTC) of 0.7¢ per kWh, which includes above-market IPP power contracts, levied on the consumption of electricity to service the $7.8 billion in residual stranded debt.

There are a number of assumptions and uncertainties associated with the valuation process that could impact the level of residual stranded debt, currently identified at $7.8 billion. These include the following: (i) The used fuel and nuclear waste liability could exceed that assumed in the financial restructuring process. Due to the proposed nuclear-risk sharing agreement, the province and OPG nuclear liabilities could rise. (ii) The valuation of Hydro One reflects the book value of assets for regulatory purposes, rather than the market value that would be applicable in a sale of assets. (iii) The valuation of OPG was derived using a discounted cash flow methodology. The assumptions used in the process, including electricity prices, the discount rate, and the success of the nuclear asset optimization program ("NAOP") could differ substantially from actual results. (iv) The value of dedicated revenue streams ($13.1 billion) is also subject to material uncertainties including the underperformance of the successor companies, and in particular nuclear generating assets, the distribution of proceeds with respect to OPG asset sales (it must reduce market share to 35% from the current 85% by 2010), the impact of transfer taxes resulting from the potential acquisition of MEUs, and the impact of the 3.8¢ per kWh price cap (until 2004) in the electricity generation market.

Ontario Hydro Stranded Debt Costs as at April 1, 1999

	Cdn$ billions
Short-term debt	$ 2.8
Long-term debt	27.7
Non-utility generation contracts	5.3
Used fuel and nuclear waste provision	2.3
Total debt & liabilities assumed by OEFC	$ 38.1
LESS: Value of successor companies	
Ontario Hydro Services Company Inc.	$ 8.6
Ontario Power Generation Inc.	8.5
IMO/ESA	0.1
	$ 17.2
EQUALS: Gross stranded debt	$ 20.9
LESS: P.V. of dedicated revenue streams	13.1
EQUALS: Residual stranded debt	$ 7.8

Hydro One Inc.	($ billions)	(%)	*Ontario Power Generation Inc.*	($ billions)	(%)
Total debt	4.845	56.3%	Total debt	3.422	40.0%
Preferred equity	0.323	3.8%	Preferred equity	0.000	0.0%
Common equity	3.436	39.9%	Common equity	5.126	60.0%
Total capitalization	8.604	100.0%	Total capitalization	8.548	100.0%

Hydro-Québec

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

Current Report: July 4, 2001
Previous Report: August 1, 2000

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RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Long-Term Debt

RATING HISTORY	Current	2000	1999	1998	1997	1996	1995
Long-Term Debt	"A"	"A"	A (low)	A (low)	A (low)	A (low)	"A"

UPDATE

DBRS confirms Hydro-Québec's ("the Company") long-term at "A" with a Stable trend. The ratings are a flow through of the rating of the Province of Québec (see separate report dated July 4, 2001), which unconditionally guarantees the Company's debt. The Company's operating income (DBRS-adjusted) was up 12.9% in Q1 2001 (year-over-year basis) following a 5.9% increase in 2000, and the medium-term outlook remains favourable primarily due to the high electricity prices and tight supply in the Northeast U.S. The high electricity prices and tight supply in the Northeast U.S. are positive for the Company's net export revenues given its low-cost hydro-based generation and its very low-cost, long-term contract for Churchill Falls power, as well as the new generation capacity expected to come on line later in 2001. In addition, ample water storage capability provides the Company with significant flexibility to export power at peak rates, thereby maximizing export revenues. However, the growth in export revenues will remain constrained due to limited interconnections and the limited transmission capacity available in the Northeast U.S. Although continued growth is expected in the domestic industrial sector, DBRS does not expect the domestic market to be a significant contributor to the Company's income growth over the near term as domestic rates are frozen at 1998 rates until at least 2002.

The Company generated strong operating cash flows in 2000, which were sufficient to cover capital expenditures and dividends. However, the $1.6 billion acquisition of Transelec, the largest transmission company in Chile, had to partially be financed with debt. As a result, the level of net debt (net of sinking fund assets) increased in 2000, but the percentage of net debt in the capital structure remained stable at 73.6%. Based on recent historical experience and on projected annual capital investments of $2.0 billion-$2.4 billion over the 2001-2003 period, cash flows are expected to be sufficient over the medium term to cover internal needs. It is expected that the Company will generate free cash flow surpluses over the medium term, which will be used to pay down debt. Interest costs should begin to decline as debt is paid down, although interest costs are sensitive to changes in the exchange rate due to the Company's foreign exchange exposure. EBIT interest coverage should improve, although it will remain below that of investor-owned utilities.

CONSIDERATIONS

Strengths:

- Debt is unconditionally guaranteed by province
- Competitive cost structure, low-cost hydro-based own generation + inexpensive power from Churchill Falls
- Significant water storage capacity allows for strategic energy trading and maximization of export revenues
- 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 at least 2002
- FX exposure and sensitivity to water levels increase volatility of earnings and cash flows
- Limited interconnections restrict export capacity
- Natural gas a longer-term competitive threat
- New regulatory environment

FINANCIAL INFORMATION

	12 months	For the years ended December 31				
	March 2001	2000	1999	1998	1997	1996
EBIT interest coverage (times)	3.00	1.28	1.24	1.18	1.22	1.11
Net debt* in capital structure	73.3%	73.6%	73.5%	74.8%	74.8%	75.6%
Cash flow/total debt (times)	0.08	0.08	0.07	0.06	0.06	0.05
Cash flow/capital expenditures (times)	0.99	0.90	1.25	1.03	1.11	0.99
Net income ($ millions)	1,158	1,078	906	679	786	520
Operating cash flow ($ millions)	3,460	3,256	2,779	2,343	2,357	2,039
Electricity sales (millions of kWhs)	195,480	190,080	171,712	161,373	162,533	163,402
Electricity revenues (¢ per kWh sold)	5.59	5.35	4.95	4.96	4.88	4.68
Variable costs (¢ per net gen kWh sold)	-	1.40	1.27	1.28	1.16	2.02
Fixed costs (¢ per net gen kWh sold)	-	3.82	4.07	4.37	3.96	4.16
Average coupon on long-term debt	-	8.82%	8.71%	8.80%	8.91%	9.13%

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.

REGULATION

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: (a) 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 sites with a capacity of over 50 MW; and (b) 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 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, given the low cost of power offered by Hydro-Québec, none of the other distributors in the province had exercised the option.

CONSIDERATIONS

Strengths: (1) Hydro-Québec's debt (excluding roughly $223 million in capital leases) is unconditionally guaranteed by the provincial government. As such, the rating assigned to the Company is a flow through of the rating of the Province of Québec.
(2) Hydro-Québec's cost structure is very competitive, largely a result of its low cost of power. Its own generating capacity is almost entirely hydro-based, which is the most cost efficient form of electricity generation, thus resulting in one of the lowest variable cost structures in Canada. Furthermore, it purchases almost all of the power generated from Churchill Falls (in Labrador) until 2041 at rates equal to 0.25¢ per kWh, falling to 0.20¢ per kWh between 2016 to 2041. Hydro-Québec sells the electricity primarily to Québec customers within Hydro-Québec's tariff base, generating income in excess of $600 million per year from this power. The Company has also signed a winter capacity contract with CF(L)Co (Churchill Falls), which provides it with additional winter capacity at a maximum cost of $1.3 billion over 42 years.
(3) The Company, through its reservoirs, benefits from almost unlimited water storage capacity, which provides for strategic energy trading. This allows Hydro-Québec to buy low-cost power during off-peak periods and sell self-generated power at higher rates during peak demand periods to maximize export revenues. In addition, the storage capacity greatly simplifies its own peak shaving needs, since hydro generation is simple to turn on and off.
(4) The Company is expected to continue to generate positive free cash flows over the medium term, which should permit it to pay down its debt, thus reducing its interest expenses (assuming the Canadian dollar does not significantly depreciate) and improving its profitability.
(5) With its indirect investment in Gaz Métropolitain (a) natural gas distributor), the Company is in a good position to benefit from the trend towards energy convergence.
(6) Both provinces on either side of Québec, New Brunswick and Ontario, have been having problems with their nuclear reactors. Hydro-Québec has surplus generating capacity and, as such, these provinces represent attractive markets for Québec. In addition, the Company's export subsidiary obtained a FERC power marketing license in 1997, which has enhanced its access to U.S. markets. In return, the Company had to grant U.S. utilities reciprocal (wholesale) access within the Province of Québec. However, Hydro-Québec has not given up much due to its competitive advantage in terms of its low-cost hydro-based energy, the low Canadian dollar, and the monopoly granted to Hydro-Québec by the Régie de l'énergie for the annual supply of wholesale power up to 165 TWh (domestic sales are currently at about 152 TWh) at a fixed price of 2.79¢/kWh. Hydro-Québec's export capability should also benefit from industry restructuring in the U.S., especially given the creation of regional transmission organizations in the U.S., which will reduce transmission costs and the "pancaking" of rates.

Challenges: (1) With debt levels remaining at about 74% of total capital, Hydro-Québec continues to have a weaker balance sheet relative to investor-owned utilities, which typically have debt/capital ratios of about 55%. Although the vast majority of the debt is unconditionally guaranteed by the provincial government, the high level of debt nevertheless results in higher interest expenses and, thus, constrains profitability and results in weak interest coverage ratios.
(2) Although operating income (DBRS-adjusted) was up 5.9% in 2000, the profitability of the Company's domestic electricity operations continues to be constrained by the rate freeze in effect until at least 2002. It is not yet known whether the provincial government will allow the rate freeze to be lifted in 2002 given the political sensitivity to rising electricity prices.
(3) The Company's earnings and cash flows are sensitive to: (a) changes in water levels, given the dominance of hydro-based generating capacity; and (b) changes in the exchange rate, given that the Company's net foreign exchange exposure. At the end of 2000, the Company's net FX exposure (taking into account all hedges) stood at about 12% of long-term debt. The Company has been reducing its net FX exposure and it currently stands at about 10%. Although it has come down significantly, the Company's earnings and, particularly cash flows, remain sensitive to movements in the exchange rate.
(4) Hydro-Québec has limited interconnections, which restrict export capacity and, consequently, earnings growth. Export capacity to Ontario, which is currently particularly constrained, should increase in the medium term given the project to build a new 1,250 MW interconnection. However, the project is currently delayed as a result of delays in obtaining certain permits from the Ontario government.
(5) Natural gas, which can be used to generate electricity or as an alternative form of energy, remains a longer term competitive threat. More recently, the flow of natural gas

from the Sable Offshore Energy Project to the U.S. Northeast through the Maritimes and Northeast Pipeline (see separate DBRS report) and the Portland Natural Gas Transmission System have extended this competitive threat to export markets in the U.S. Northeast.

(6) The establishment of the Régie de l'énergie in 1996 and the amendments made to the regulatory environment in 2000 increase the regulatory risk for Hydro-Québec.

EARNINGS

Hydro-Québec

Income Statement

($ millions)	12 mos. ended	For years ended December 31				
Revenues:	March 2001	2000	1999	1998R	1997	1996
Residential/farm	n/a	3,167	3,034	2,906	3,066	2,945
Commercial/institutional	n/a	2,002	1,963	1,894	1,885	1,835
Industrial	n/a	2,405	2,236	2,177	2,162	2,061
Other	n/a	220	215	216	218	226
Subtotal domestic revenues	7,865	7,794	7,448	7,193	7,331	7,067
Exports (long-term) *	n/a	377	427	391	350	292
Exports (short-term) *	n/a	2,003	624	423	246	296
Subtotal export revenues	3,071	2,380	1,051	814	596	588
Total electricity revenues	10,936	10,174	8,499	8,007	7,927	7,655
Other	1,398	1,255	1,109	805	360	25
Total revenues	12,334	11,429	9,608	8,812	8,287	7,680
Expenses:						
Operating & administration	2,140	2,135	1,912	1,681	1,602	1,542
Electricity purchases	2,418	1,715	544	472	292	250
Fuel costs	n/a	693	565	427	237	25
Decommissioning	n/a	12	10	9	8	7
Depreciation & amortization	1,894	1,884	1,721	1,580	1,537	1,420
Property + capital taxes	524	525	592	610	582	568
Debt guarantee fee	187	187	197	189	188	192
Total operating costs	7,868	7,151	5,541	4,968	4,446	4,004
Operating income	4,466	4,278	4,067	3,844	3,841	3,676
Interest expense	n/a	3,231	3,177	3,272	3,153	3,312
Non-cash financial charges	n/a	(181)	(144)	(109)	(98)	(166)
Other (income) / FX / expense	n/a	132	115	(9)	(6)	10
Net interest expense	3,290	3,182	3,148	3,154	3,049	3,156
Income before minority interest	1,176	1,096	919	690	792	520
Less: non-controlling interest	18	18	13	11	6	0
Net income	1,158	1,078	906	679	786	520

Operating income (DBRS-adjusted) continued to grow in the first quarter of 2001, following a strong 5.9% increase in 2000 to $4.3 billion. Earnings also registered robust growth, rising 20% in 2000 to top the $1 billion mark. The strong growth was a result of sharply higher electricity revenues, which more than offset the increase in operating costs and interest costs. The increase in electricity revenues was led by: (1) the jump in electricity exports, which have much higher margins than domestic sales due to the current high spot prices in the Northeast U.S.; and (2) the 3.9% increase in domestic sales volumes. The surge in electricity exports was entirely driven by short-term sales due to the higher market prices for electricity. The establishment by the Company of an energy trading floor in 2000 permitted the Company to maximize its participation in the regional energy exchanges. On the domestic front, a variety of factors worked together to account for the robust growth in electricity sales, including: (a) increased industrial demand related to the strong economic growth in 2000; (b) colder weather relative to 1999; (c) increased demand from customers having dual-energy systems due to the high oil and natural gas prices; and (d) higher aluminum prices as Hydro-Québec has sales contracts whereby the rates are based on the price of aluminum.

***Outlook*:** The outlook for the Company's earnings remains favourable given its fundamental strengths, namely: (a) its low-cost hydro-based generating capacity; and (b) a long-term (until 2041), very low-cost purchase contract for Churchill Falls power. Furthermore, electricity demand out of the Northeast U.S. remains strong and market prices remain high, providing significant support to the Company's earnings in the short term. However, earnings growth in the domestic market will continue to be limited by the domestic rate freeze in effect until at least 2002. The slowdown in the economy could also have a dampening effect on earnings growth. However, this is likely to be largely mitigated by the positive impact on electricity demand of continued high oil and natural gas prices. Over the next four years, the Company projects earnings to grow to about $1.6 billion by 2004, based on the following assumptions included in the Company's Strategic Plan 2000-2004: (1) electricity sales volume growth of about 2% over the 2000-2004 period, with most of the growth occurring within Québec; (2) a 38% increase in selling prices in U.S. exports markets, which is expected to offset projected declines in export electricity sales; and (3) lower financial expenses over the longer term as a result of debt reduction and a stronger Canadian dollar.

However, given the mostly debt-financed, $1.6 billion acquisition of Transelec (the principal transmission system in Chile) in 2000, DBRS does not expect the Company's financial expenses to decline much over the medium term from their 1999 level. Furthermore, it remains highly uncertain whether the Canadian dollar will strengthen over the medium term (a higher percentage of the Company's debt is denominated in U.S. dollars).

Given the slowdown in the economy and the freeze on rates in Québec, combined with the new generation capacity expected to come on line in 2001 and the high electricity prices and tight supply in the Northeast U.S., DBRS expects that the majority of the Company's earnings growth in the medium term will come from the export market. Furthermore, once Hydro-Québec's long-term sales contracts expire (a number expire in 2001 and 2002), additional capacity will be freed up, which will allow the Company to sell even more electricity into the U.S. short-term market at higher prices. However, the growth of exports could be constrained by the limited transmission capacity available in the Northeast U.S. relative to the demand requirements. The Company's ongoing investments outside North America should also positively contribute to its earnings over the longer term.

Financial Profile

Statement of Cash Flows	12 mos ended	For years ended December 31				
($ millions)	Mar-01	2000	1999	1998R	1997	1996
Net income	1,158	1,078	906	679	786	520
Depreciation & amortization	2,180	2,036	1,920	1,782	1,573	1,514
Other non-cash charges	122	142	(47)	(118)	(2)	5
Operating cash flow	3,460	3,256	2,779	2,343	2,357	2,039
Less: dividends	453	453	279	357	357	0
Less: capital expenditures	1,830	1,812	1,642	2,092	1,590	2,056
Cash flow before working capital	1,177	991	858	(106)	410	(17)
Less: changes in working capital	2	(89)	(105)	118	(389)	34
Free cash flow	1,175	1,080	963	(224)	799	(51)
Less: other investments	1,654	1,809	585	185	543	(9)
Plus: net financing	607	806	(311)	345	(403)	(288)
Net change in cash	128	77	67	(64)	(147)	(330)
Net debt (net of sinking fund assets)	41,780	40,236	38,659	39,860	38,698	38,641
% net debt in capital structure	73.3%	73.6%	73.5%	74.8%	74.8%	75.6%
EBIT interest coverage	1.36	1.28	1.24	1.18	1.22	1.11

As was the case in 1999, the Company's cash from operations in 2000 was more than sufficient to cover capital expenditures and dividends to the Province of Québec. However, its internally generated cash flows were not sufficient to cover the $1.6 billion acquisition of Transelec, a transmission company in Chile. The Company financed the acquisition using short-term bridge financing, and had not yet permanently financed the transaction as at the end of 2000. In April 2001, Transelec completed its permanent financing by issuing US$700 million of bonds (without recourse to Hydro-Québec). In 2000, the Company's level of net debt (net of sinking fund assets) on the balance sheet increased by $1.6 billion; however, a large portion of the increase (about 46%) was due to exchange rate effects.

Despite the increase in the level of net debt, the percentage of net debt in the capital structure remained stable at 73.6% as at December 31, 2000. While there has been some improvement, albeit modest, in the debt-to-capital ratio over the past five years, it remains high compared to the 55% average debt-to-capital ratio typical of investor-owned utilities, thus constraining profitability and EBIT interest coverage ratios. As a result, EBIT interest coverage ratios have consistently remained below 1.3 times, compared to the 3.0 times typical of the private sector. However, it should be noted that as a Crown corporation, Hydro-Québec faces certain restrictions that investor-owned utilities do not face, such as the lack of access to equity markets. Furthermore, given that its sole shareholder is a government, which has non-financial objectives, its dividend payout structure can be significantly different from investor-owned utilities. As a result, its capital structure and other financial ratios may not necessarily be the same as those of investor-owned utilities.

Outlook: Cash flows from operations are expected to be sufficient in 2001 to finance the Company's total investment program (capital expenditures plus acquisitions and other investments) projected to be around $2.4 billion. They are also expected to be sufficient to cover the Company's dividend payments. The Company is expecting to record a reduction in net debt in 2001. However, given the high percentage of US$ debt (50% of debt is in U.S. dollars), the level of debt recorded on the balance sheet may not show a decline if the Canadian dollar depreciates from its December 31, 2000, level.

Over the medium term (2002-2004), the Company is projecting annual operating cash flows of between $2.6 billion and $3.2 billion, as outlined in its Strategic Plan 2000-2004. Capital expenditures including investments are expected to remain in the $2.0 billion-$2.3 billion range (compared to historical levels as high as $4 billion) in 2002 and 2003, and then up to $3.1 billion in 2004. Over the medium term, the Company expects that operating cash flows will be sufficient to finance its internal cash needs and that it will be in a position to pay down its debt. Balance sheet leverage is expected to continue to decline, assuming the Canadian dollar does not significantly depreciate during this time. EBIT interest coverage should continue to increase slowly, in line with projected growth in EBIT and the declining level of debt. However, interest coverage remains vulnerable to changes in the exchange rate.

Operating Lines of Credit

The Company has a Cdn$350 million (or US$350 million) line and a Cdn$40 million line with Canadian banks, and a US$50 million line of credit with a U.S. bank. These lines of credit are not guaranteed by the provincial government. In addition, it has revolving standby lines of credit equal to US$1,500 million. The standby lines are guaranteed by the provincial government. The lines of credit support a US$2.75 billion commercial paper program. As at December 31, 2000, the Company had Cdn$45.8 million of commercial paper outstanding

Term Debt Maturity Schedule

	2001	2002	2003	2004	2005	Beyond 5 years
(Cdn$ millions)*	3,484	3,011	2,891	1,203	2,302	25,480

*The Government of Québec guarantees all but $223 million (largely consisting of capital leases) of the Company's outstanding $40.2 billion debt. The variable rate portion accounts for about 26.3% of outstanding debt (including perpetual debt). A 1% change in interest rates would impact net earnings by about $101 million, excluding the impact of financial derivatives.

Generation Projects

In 2000, much of Hydro-Québec's expenditures were related to maintaining the reliability of its existing generation facilities. The Company completed rehabilitation work on its La Gabelle, La Tuque and Tracy generating stations in 2000. Furthermore, construction continued on Sainte-Marguerite-3. This new hydro-based generating facility is expected to be commissioned in the fall of 2001, and will add 882 MW of capacity. The next major generation project to be undertaken by Hydro-Québec is the recently approved construction of the new Grand-Mère hydro facility (220 MW), which will replace the existing facility. The projected cost is $460 million and it is expected to be commissioned in 2004. Hydro-Québec also recently received approval to begin construction of the Toulnustouc generating facility (526 MW) on the North shore, to be commissioned in 2005.

A variety of other projects within Québec are in the negotiating, discussing or planning phases, and could add significant generation capacity. Furthermore, the Company is in negotiations with Newfoundland and Labrador Hydro regarding the development of Lower Churchill. The negotiations are centered on a purchase agreement for the electricity that would be generated by this new hydro facility.

Province of Québec

The Province of Québec's ("the Province") long-term and short-term ratings were confirmed at "A" and R-1 (low), respectively, both with Stable trends (see separate report dated July 4, 2001). Over the past six years, the Province has managed to significantly reduce the gap between revenues and expenditures that has historically plagued the Province's finances. Strong economic growth, tighter spending controls and various legislative measures adopted in recent years to improve accountability have led to a marked improvement in the Province's DBRS-adjusted balance, which grew from a deficit of $7.5 billion in 1994 - 1995 to an unexpected surplus of $294 million in 2000-2001. For 2001-2002, a DBRS-adjusted deficit of $1.2 billion is expected. Although lower than last year's performance, it remains consistent with the Province's balanced budgets. The Province also has a stronger, more diversified economy, supported by important knowledge-based industries and a very competitive corporate tax system. The strengthened economic fundamentals have resulted in a broader fiscal revenue base and more sustainable long-term growth opportunities for the Province, as reflected in the 2.7% real GDP growth forecast for 2001.

Despite significant progress achieved in recent years, the Province continues to face challenges. Total tax-supported debt, in particular, is relatively high. At 60% of provincial GDP, it represents the second highest debt burden among all provinces. In addition to limiting the Province's flexibility, high indebtedness consumes a significant portion of fiscal revenues (18% in 2000-2001). Upward pressure on indebtedness is expected to remain in the near future, as the Province's balanced budgets will likely continue to require external financing to cover non-budgetary items. In 2001-2002, total tax-supported debt is projected to increase by at least $5.5 billion, to $136.2 billion, which should put an end to the decline in the debt-to-GDP ratio. Despite the tax cuts delivered to Québecers in the last two budgets, personal income taxes remain relatively high, especially compared to Ontario. Other risks include the high levels of foreign currency and floating rate debt maintained by the Province and the current government's commitment to sovereignty.

Hydro-Quebec

Balance Sheet
($ millions)

Assets	March 2001	As at Dec. 31 2000	1999	Liabilities & Equity	Mar-01	As at Dec. 31 2000	1999
Cash + equivalents	1,574	746	488	Net short-term debt	4,880	5,169	2,514
Accts receivable	2,639	1,861	1,875	A/P + accrued	3,167	3,274	2,966
Other	435	407	381	Current liabilities	8,047	8,443	5,480
Current assets	4,648	3,014	2,744	Long-term liabilities	720	586	596
Net fixed assets	49,779	49,640	48,226	Net long-term debt	36,348	34,515	35,593
Investments	748	750	702	Other liabilities	194	274	265
Deferred expenses	5,033	4,309	3,874	Perpetual debt	552	552	552
Other	688	937	681	Shareholders' equity	15,035	14,280	13,741
Total	60,896	58,650	56,227	Total	60,896	58,650	56,227

Ratio Analysis	12 mos. end	For years ended December 31						
Liquidity Ratios	March 2001	2000	1999	1998	1997	1996	1995	1994
Current ratio	0.58	0.36	0.52	0.49	0.61	0.61	0.69	0.89
Accumulated depreciation/gross fixed assets	-	24.1%	22.9%	21.3%	19.8%	18.1%	16.6%	15.5%
Cash flow/total net debt (1)	0.08	0.08	0.07	0.06	0.06	0.05	0.04	0.05
Cash flow/capital investments (2)	0.99	0.90	1.25	1.03	1.11	0.99	0.63	0.60
Cash flow-dividends/capital investments (2)	0.86	0.77	1.12	0.87	0.94	0.99	0.63	0.60
Net debt in capital structure (1)	73.3%	73.6%	73.5%	74.8%	74.8%	75.6%	76.6%	76.5%
Average coupon on long-term debt	-	8.82%	8.71%	8.80%	8.91%	9.13%	9.40%	9.69%
Common equity in capital structure (1)	26.7%	26.4%	26.5%	25.2%	25.2%	24.4%	23.4%	23.5%
Common dividend payout (based on div declared)	0.0%	50.0%	50.0%	41.1%	45.4%	0.0%	0.0%	0.0%
Coverage Ratios (3)								
EBIT interest coverage	1.36	1.28	1.24	1.18	1.22	1.11	1.06	1.07
EBITDA interest coverage	1.93	1.87	1.79	1.66	1.71	1.54	1.40	1.41
Fixed-charges coverage	1.36	1.28	1.24	1.18	1.22	1.11	1.06	1.07
Earnings Quality / Operating Efficiency								
Power purchases/revenues (4)	19.6%	15.0%	5.7%	5.4%	3.5%	3.3%	3.4%	3.6%
Fuel costs/revenues	n/a	n/a	n/a	4.8%	2.9%	0.3%	0.2%	0.4%
Operating margin	36.2%	37.4%	42.3%	43.6%	46.3%	47.9%	48.5%	47.7%
Net margin (before extras.)	9.4%	9.4%	9.4%	7.7%	9.5%	6.8%	5.1%	9.2%
Return on avg. equity (before extras.) (1)	7.8%	7.6%	6.6%	5.1%	6.2%	4.3%	3.3%	5.9%
Profit returned to government (5)	62.3%	65.1%	63.0%	78.2%	72.4%	59.4%	65.2%	50.0%
Customers/employee	-	171	172	167	169	147	136	132
Growth in customer base	-	0.7%	0.7%	0.7%	0.9%	1.3%	1.1%	1.1%
GWh sold/employee	-	9.2	8.4	7.7	8.0	7.0	6.7	6.2
Self Generation - Cost Structure (6) (7)								
OM&A	-	1.36	1.20	1.23	1.14	1.51	1.32	1.24
Fuel	-	0.04	0.07	0.05	0.02	0.51	0.41	0.33
Variable costs	-	1.40	1.27	1.28	1.16	2.02	1.73	1.57
Government levies	-	0.52	0.60	0.64	0.58	0.52	0.57	0.62
Net interest expenses	-	2.18	2.37	2.61	2.35	2.39	2.30	2.44
Total cash costs	-	4.11	4.24	4.54	4.09	4.93	4.60	4.62
Non-cash financial charges	-	(0.18)	(0.15)	(0.14)	(0.12)	(0.13)	(0.10)	(0.08)
Depreciation	-	1.29	1.24	1.25	1.14	1.38	1.23	1.21
Total costs	-	5.22	5.33	5.65	5.12	6.18	5.73	5.75
Purchased power (cents per gross kWh purch.)	-	2.98	1.27	1.07	0.89	5.87	1.84	1.53
Churchill Falls power (cents per gross kWh purch.)	-	0.37	0.38	0.34	0.27	0.29	0.30	0.28
Purch. power (excl CF) (cents per gross kWh purch.)	-	6.19	3.76	3.52	5.51	5.05	6.06	5.32
Average domestic unit revenue (cents per kWh sol	-	5.10	5.07	5.04	4.98	5.10	5.07	5.04
Total unit costs - self generation	-	5.22	5.33	5.65	5.12	6.18	5.73	5.75
Net margin excl Churchill Falls contribution	-	(0.12)	(0.27)	(0.62)	(0.14)	(1.07)	(0.66)	(0.71)

(1) Minority interest treated as a common equivalent. Debt including perpetual debt, net of sinking fund assets. (2) Excludes other investment expenditures before 1996.
(3) Before capitalized interest, AFUDC, debt amortizations. (4) From 1999 onward includes fuel costs. (5) Includes all taxes, debt guarantee fees and dividends.
(6) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

Electricity Sold (Breakdown)	2000	1999	1998	1997	1996	1995
	For years ended December 31					
Residential/farm	51,666	49,315	47,701	51,246	50,294	48,842
Commercial/institutional	30,490	29,765	28,815	29,560	29,158	29,108
Industrial	65,950	63,409	61,773	61,837	59,797	59,254
Other	4,651	4,500	4,519	4,648	5,261	4,832
Total domestic	152,757	146,989	142,808	147,291	144,510	142,036
Exports (long-term) *	6,844	8,711	8,101	8,072	7,819	8,975
(short-term) *	30,479	16,012	10,464	7,170	11,073	15,090
Total exports	37,323	24,723	18,565	15,242	18,892	24,065
Total (GWh sold)	190,080	171,712	161,373	162,533	163,402	166,101
Domestic energy growth	3.9%	2.9%	-3.0%	1.9%	1.7%	2.2%
Export energy growth	51.0%	33.2%	21.8%	-19.3%	-21.5%	25.6%
Total energy growth	10.7%	6.4%	-0.7%	-0.5%	-1.6%	5.0%

Unit Revenues	12 mos ended	For years ended December 31				
Revenues:	March 2001	2000	1999	1998R	1997	1996
Residential/farm	n/a	6.13	6.15	6.09	5.98	5.86
Commercial/institutional	n/a	6.57	6.59	6.57	6.38	6.29
Industrial	n/a	3.65	3.53	3.52	3.50	3.45
Other	n/a	4.73	4.78	4.78	4.69	4.30
Subtotal domestic	5.12	5.10	5.07	5.04	4.98	4.89
Exports (firm)	n/a	5.51	4.90	4.83	4.34	3.73
Exports (short-term)	n/a	6.57	3.90	4.04	3.43	2.67
Average electricity revenues	5.62	5.35	4.95	4.96	4.88	4.68

Generation							
Hydro	93%	29,246	29,235	29,203	29,203	29,220	28,932
Oil + diesel	5%	1,591	1,595	1,594	1,519	1,518	1,518
Nuclear	2%	675	675	675	675	675	675
Installed capacity (MW)		31,512	31,505	31,472	31,397	31,413	31,125
Available hydro (Churchill Falls)		5,428	4,765	4,083	4,213	4,213	4,213
Energy generated (GWh)							
Hydro		n/a	137,416	125,774	136,907	141,878	145,306
Nuclear		n/a	3,845	4,083	4,535	5,582	4,826
Oil		n/a	570	922	142	225	267
Natural gas		n/a	570	922	198	7	9
Gross energy generated (1)	72%	145,960	142,400	131,700	141,726	147,692	150,408
Plus: Churchill Falls purchases	16%	31,727	31,405	34,137	30,301	25,748	26,693
Other energy exchanges (2)	13%	25,793	11,307	10,200	4,006	3,451	2,899
Energy generated + purchased (2)		203,480	185,112	176,037	176,033	176,891	180,000
Less: transmission losses + internal use (2)		13,400	13,400	14,664	13,500	13,489	13,899
Total (GWh sold)		190,080	171,712	161,373	162,533	163,402	166,101
Energy lost + used/energy gen + purch		6.6%	7.2%	8.3%	7.7%	7.6%	7.7%
Primary peak demand (MW)		33,767	35,577	35,275	32,305	34,642	33,594
Peak demand/installed capacity		107.2%	112.9%	112.1%	102.9%	110.3%	107.9%
Peak demand/installed capacity ^		91.4%	98.1%	99.2%	90.7%	97.2%	95.1%
Export Interconnections (MW)							
Ontario Power Generation		1,195	1,195	1,195	1,462	1,462	1,462
New Brunswick Power		1,200	1,200	1,200	1,060	1,060	1,060
New England Utilities		2,305	2,303	2,303	2,303	2,303	2,303
New York		2,695	2,695	2,695	2,695	2,695	2,695
Total		7,395	7,393	7,393	7,520	7,520	7,520
Interconnections as a percentage of installed capacity		23.5%	23.5%	23.5%	24.0%	23.9%	24.2%

(1) DBRS estimate for 2000.

(2) DBRS estimates for 1997-200.

* Restated for 1996-99. Prior period amounts reflect firm and spot sales.

^ Including Churchill Falls capacity.

The Manitoba Hydro-Electric Board

(*The rating is based on the Provincial guarantee. This report specifically analyzes the Utility.)

Current Report: October 24, 2001
Previous Report: September 29, 2000

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RATING*

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Long Term Debt

RATING HISTORY* (as at March 31)

	Current	2000	1999	1998	1997	1996	1995
Long Term Debt	"A"	"A"	"A"	"A"	"A"	"A"	"A"

UPDATE

DBRS confirms the Manitoba Hydro-Electric Board's ("Manitoba Hydro" or "the Utility") rating at "A" with a Stable trend. The rating is a flow-through of the rating of the Province of Manitoba's rating, as the Utility's debt securities are direct obligations of the Province. The Utility continues to perform well, despite high debt levels. Manitoba Hydro's earnings in 2000-01 increased sharply to a record $270 million from $152 million the previous year, largely due to higher prices for electricity exports and an increase in energy available for export as a result of higher water flows. A high interconnection/capacity ratio with the U.S. and its hydro generation base are among the Utility's primary strengths and contribute to a favourable earnings growth outlook. In addition, Manitoba Hydro is continuing with its financial targets of maintaining its annual gross interest coverage ratio at a minimum of 1.20 times and to improving its debt/equity to 75/25 by 2005-06. With variable costs of about 1¢ per kWh from its predominantly hydro-based capacity, Manitoba Hydro is able to compete very effectively against all U.S. utilities in the U.S. midwest, where electricity prices range between US4.4¢ per kWh to US7.8¢ per kWh. Manitoba Hydro's acquisition of a private sector gas distribution utility in July 1999 is beginning to generate meaningful operating synergies and allow the Utility to benefit from the trend towards energy convergence. While Manitoba Hydro continues to generate sufficient cash flows to finance capital expenditures, there is little surplus cash available for debt reduction. Over the near to mid-term, exports should continue to contribute to growth in earnings and should improve key debt coverage ratios. While water rental fees were doubled on April 1, 2001, which will impact earnings, the Utility is not subject to a strict dividend policy, which typically limits debt reduction and the growth opportunities of other government-owned utilities. Current debt to capital (DBRS-adjusted) at 85% is weak, when compared to the average of all government utilities at 70% debt and the private sector in the 50%-55% range. Relative to investor-owned utilities, high debt levels result in a weaker financial profile for the Utility.

CONSIDERATIONS

Strengths:

- Debt is guaranteed by the provincial government
- Low cost hydro-based capacity: water storage capacity allows for maximization of export revenues
- Interconnections with U.S., Saskatchewan and Ontario
- Centra Gas acquisition positions Manitoba Hydro to benefit from trend in energy convergence

Challenges:

- High debt level weakens most financial ratios
- Earnings are sensitive to water levels
- Sensitivity to currency exchange rates: 48% of debt dominated in U.S. dollars
- Domestic energy rates have not increased since 1992
- One NFA First Nation claim not settled

FINANCIAL INFORMATION

	12 mos.	For years ended March 31						
	2001	2000	1999	1998	1997	1996	1995	1994
EBIT interest coverage (times)	1.53	1.31	1.19	1.22	1.21	1.15	1.13	1.12
Net debt in capital structure (1)	85.3%	88.1%	89.5%	90.8%	92.4%	93.8%	95.0%	96.1%
Cash flow/total debt (times)	0.08	0.06	0.06	0.06	0.06	0.05	0.04	0.05
Cash flow/capital expenditures (times)	1.43	1.15	0.98	1.35	1.03	1.00	1.03	0.94
Net income ($ millions)	270	152	100	111	101	70	56	69
Operating cash flow ($ millions)	519	379	325	334	307	271	241	254
Electricity sales (millions of kWhs)	28,806	26,688	27,692	29,462	27,567	25,460	24,165	24,103
Electricity revenues (cents per kWh sold)	4.38	4.17	3.88	3.52	3.69	3.85	3.88	3.81
Variable costs (cents per net gen kWh sold)	1.10	1.11	0.94	0.75	0.84	0.91	0.94	0.94
Fixed costs (cents per net gen kWh sold)	2.81	2.93	2.69	2.41	2.50	2.70	2.73	2.64
Average coupon on long-term debt	8.31%	8.38%	8.56%	8.79%	8.74%	9.22%	8.49%	8.41%

(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. The Utility acquired the province's private sector gas distributor, Centra Gas Manitoba, in July 1999.

CONSIDERATIONS

<u>Strengths</u>: (1) *Debt securities are direct obligations of, or are guaranteed by, the* provincial government - As such, the rating assigned to Manitoba Hydro is a flow-through of the rating of the Province of Manitoba.

(2) Low cost hydro-based capacity - Hydro-based generating capacity accounts for 95% of installed capacity and results in one of the lowest variable cost structures in Canada (near 1¢ per kWh), surpassed only by Churchill Falls in Labrador. Given the water storage capacity of its hydro-based power generating facilities, Manitoba Hydro is in an excellent position to trade power, buying low cost power during off-peak hours, and selling its own generated power during peak periods at higher rates. Geographically diverse drainage basins reduce fluctuations in water flows and water levels caused by weather patterns in a specific region.

(3) *Interconnections with the U.S. markets, Saskatchewan and Ontario* - Manitoba Hydro has excellent interconnections (about 55% of installed capacity) with 2,050-MW to the U.S. MAPP power pool, 450-MW to Saskatchewan and 263-MW to Ontario. This provides additional markets to sell power.

(4) *Centra Gas acquisition* - The $300 million acquisition of the provincial gas distributor, Centra Gas Manitoba, from Westcoast Energy Inc., puts the Utility in a good position to benefit from the trend in energy convergence. In addition, there is a potential for material operating synergies that could benefit both the electricity and gas distribution operations. The successful integration of Centra Gas will take some time, given the different corporate cultures of the two entities involved.

<u>Challenges</u>: (1) *High debt level weakens most financial ratios* - Debt levels remain high and largely account for consistently weak financial ratios.

(2) *Earnings sensitive to water levels* - The hydro-based nature of the Utilty's generating facilities can contribute to fluctuations in earnings and interest coverage ratios over the shorter-term and can potentially affect export sales. This is partly mitigated by the Utility's diverse drainage basins.

(3) *Sensitivity to currency exchange rates* - Although the book value of foreign dollar debt has been fixed, the Utility remains sensitive to exchange rates. Approximately 45% of outstanding debt at March 31, 2001, was U.S. dollar denominated, and would have been $1,008 million higher adjusted for prevailing exchange rates. While U.S. dollar interest costs and principle repayments are fully covered by U.S. export energy revenues, surplus revenues are sensitive to exchange rates, which will have an impact on earnings.

(4) *Domestic energy rates have not increased since 1992* – Domestic rates for large industrial customers have been voluntarily frozen since 1992 and since 1997 for residential customers, and will not be increased in 2001-02. Electricity rates in Manitoba are among the lowest in North America, and contribute to weaker profitability. Low rate may benefit the Utility by creating a barrier to entry for competitors.

(5) *One Northern Flood Agreement (NFA) First Nation claim not settled* – Manitoba Hydro continues to address the adverse effects of its northern hydroelectric developments on five First Nation communities. The Utility has an agreement (Northern Flood Agreement) with the Provincial Government to assume certain obligations of the Province associated with these northern development projects. Four out of five native claims have reached a settlement.

EARNINGS

	For years ended March 31						
($ millions)	2001	2000	1999	1998	1997	1996	1995
Revenues	1,393.0	1,211.0	1,081.6	1,041.1	1,022.6	984.6	940.9
EBITDA	996.0	838.0	764.0	773.5	749.1	690.9	671.9
EBIT	747.0	611.0	566.0	582.5	571.7	522.4	512.1
Net interest expense	489.0	468.0	474.9	476.7	472.1	454.4	454.1
Net income	270.0	152.0	100.1	110.5	101.1	70.1	55.9

Net earnings in 2000-01 increased 78% to a record $270 million from $152 million last year. The sharp increase in net earnings is attributable to the following factors. (1) A 28% increase in export revenues to an all-time high of $480 million. Sixty per cent of this increase is a result of higher electricity prices in the export market – higher prices are mainly attributable to rising natural gas prices and the expansion of competitive markets within the industry. The remaining forty percent of the increase is a result of addition energy available due to higher water flows. (2) In addition, domestic electric revenues increased by 6% to $793 million – largely due to increased residential usage as a result of colder winter weather experienced in 2000-01 and higher industrial customer demand. Total operating costs increased by 10% to $749 million primarily due to: (1) higher operating and administrative expenses, of $18 million to $289 million, associated with additional maintenance on the Utility's generation, transmission, and distribution systems; (2) increased power purchases, of $12 million to $30 million, at a higher unit price of 3.24 cents per kWh from 1.90 cents per kWh; and (3) higher depreciation costs, of $22 million to $249 million, as a result of various projects being place into service as well as additions to general equipment, vehicles, and communication systems.

The Centra Gas operations contributed $3 million to net earnings in 2000-01.

Outlook: Given the hydro-based nature of power generation, the Utility's earnings and profitability remain sensitive to water levels. Earnings should continue to benefit from the Utility's membership in the Mid-Continent Area Power Pool (MAPP), which has allowed for growth of electricity exports. Manitoba Hydro, with its low cost hydro base generation is able to compete very effectively against many U.S. utilities. The acquisition of Centra Gas Manitoba is expected to generate material synergies over the longer-term and should allow the Utility to benefit from the trend in energy convergence.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

Cash Flow Statement	Years ending March 31					**Stress Testing**		
($ millions)	2001	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	996.0	838.0	764.0	773.5	749.1	896.4	851.6	851.6
Net income (before extras.)	270.0	152.0	100.1	110.5	101.1	159.1	113.3	109.1
Depreciation & amortization	249.0	227.0	198.0	191.0	177.4	230.2	234.4	238.5
Other non-cash adjustments	0.0	0.0	27.1	32.6	28.0	0.0	0.0	0.0
Cash flow from operations	519.0	379.0	325.2	334.1	306.5	389.3	347.7	347.6
Dividends paid (received)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital expenditures	362.0	330.0	331.6	248.1	297.1	350.0	350.0	350.0
Free cash flow before working capital	157.0	49.0	(6.4)	86.0	9.4	39.3	(2.3)	(2.4)
Change in working capital	185.0	5.0	(40.6)	37.4	33.6	0.0	0.0	0.0
Gross free cash flow	(28.0)	44.0	34.2	48.6	(24.2)	39.3	(2.3)	(2.4)
Dispositions/(acquisitions)	0.0	(300.0)	0.0	0.0	0.0	0.0	0.0	0.0
Investments & other	40.0	48.0	44.8	(34.7)	80.3	0.0	0.0	0.0
Net free cash flow	(68.0)	(304.0)	(10.6)	83.3	(104.5)	39.3	(2.3)	(2.4)
Change in equity: new/(repurchased)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Change in debt: new/(repayments)	51.0	262.0	(65.5)	(57.3)	178.1	0.0	0.0	0.0
Change in net cash	(17.0)	(42.0)	(76.1)	26.0	73.6	39.3	(2.3)	(2.4)
Key Figures and Ratios:								
Total debt in capital structure (1)	6,325.0	6,070.0	5,682.4	5,579.0	5,533.9	6,285.7	6,287.9	6,290.4
% debt in capital structure (1)	85.3%	88.1%	89.5%	90.8%	92.4%	83.4%	82.2%	81.1%
EBITDA interest coverage (times)	2.04	1.79	1.61	1.62	1.59	1.73	1.66	1.66
EBIT interest coverage (times)	1.53	1.31	1.19	1.22	1.21	1.29	1.20	1.19
Cash flow/ total debt (1)	0.08	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Stress Test Assumptions:						**Assumptions**		
EBITDA growth						-10%	-5%	0%
Interest rate (based on five-year average rate)						8.2%	8.2%	8.2%

Financial Profile: Despite a substantial rise in 2001 net income, sharp growth in working capital (primarily from an increase deferred gas cost to be recovered from future billing) neutralized the benefits and free cash flow was negative. In a typical year, the Utility can fund its capital expenditures internally and strengthen its debt ratios. Despite improvement to its debt-to-capital ratio, total debt increased by $255 million to $6,325 million primarily due to an increase in the foreign exchange adjustment on foreign debt by $277 million. Thus the improvement to the debt to capital structure ratio is entirely due to the increase in retained earnings.

Outlook: With limited new projects, and its commitment to ensure capital expenditures do not exceed internally generated funds, the financial ratios of the Utility should improve slowly as long as the dividend payment to the Province is avoided.

Some of the significant near-term capital projects that Manitoba Hydro currently has underway are: (1) conversion of its Selkirk thermal generating station from coal to natural gas in 2002 along with additional environmental upgrades, for $30 million and $29 million, respectively; (2) construction of a 230 kV transmission line to North Dakota in 2002 for $19 million; and (3) construction of a 260 MW natural gas plant in Brandon for $177 million – with the first of two turbines to be commissioned in mid 2002.

Sensitivity Analysis:

(1) DBRS stress test the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Utility, nor DBRS expectations concerning the future performance of the Utility.

Under the extreme scenario shown above, with EBITDA decreasing by 10% in year 1, 5% in Year 2, and remaining constant thereafter, Manitoba Hydro would generate sufficient operating cash flows to support capital expenditures of $350 million per year (Note: three-year historical average capex is $341 million). However, the Utility would generate little free cash flow beyond Year 1, thus making it difficult to pay down debt significantly and strengthen its balance sheet. Ratios should slowly improve, even under such adverse conditions, as cash flow finances capital expenditure.

OPERATING LINES OF CREDIT

A credit facility of $500 million available either in Canadian or U.S. currency.

DEBT MATURITY SCHEDULE

($ millions)	F2002	F2003	F2004	F2005	F2006
	142	183	3	3	3

The Watersheds and Storage Capacity

Manitoba Hydro draws water from four distinct watersheds. (1) The main source is the Winnipeg River, which runs through northern Minnesota and northwestern Ontario. Because of the 900 feet of head from the source, the large volume of water, and the fact that the same water goes through virtually all the generators which are all downstream, this watershed typically accounts for about 40% of the electricity produced by Manitoba Hydro. (2) The Prairie region, which extends to the Continental Divide, is drained by the Saskatchewan River. This watershed accounts for about one-quarter of the energy produced. The watershed is large but relatively dry, and most parts of the southern prairies contribute no water runoff. (3) The Churchill River watershed, which includes northern Saskatchewan and northwestern Manitoba, contributes approximately 22% of energy generated. (4) The Red River watershed, which includes northern Minnesota, typically contributes about 4% to 15% of energy, with most of the water coming in the month of May. The remaining water comes from other areas in the province. This three-watershed base provides some diversification and stability to available water levels used to produce electricity. Water levels are amplified by two other characteristics. (1) The cold temperatures reduce evaporation rates and much of the water is frozen for up to five months a year. (2) The fact that much of the soil is rock reduces seepage and increases runoff. Lastly, Lake Winnipeg, Caedar Lake and South Indian Lake serve as large storage reservoirs. This gives the Utility the capacity to produce electricity when it wishes (i.e., when prices are higher). Electric industry restructuring and deregulation is well under way in many parts of the U.S., and competitive pressures will favour those utilities with the lowest cost structures. With access to wholesale markets in the United States through the MAPP power pool or possibly other organizations, Manitoba Hydro is in a good position to sell electricity to more users in the U.S. at higher prices. The Utility's water storage capacity is a competitive advantage in trading electricity (buying surplus U.S. power at low off-peak prices, and selling its electricity during peak demand periods at higher prices). This will grow in the future and have the effect of ultimately raising the average unit price received for electricity sold by Manitoba Hydro.

Manitoba also has the advantage of having about 5,000 more megawatts of future generating capacity, which can be developed, virtually equal to the 5,000 megawatts of capacity presently in place. With changes to the Hydro Act, it now has the legal flexibility to form joint ventures and use third party sources to develop the power. Environmental issues are believed to be manageable, and agreements with native bands regarding new projects appear to be feasible. In addition, most infrastructure is already in place. Interest costs are also at record lows, which makes financing the projects more economic. However, transmission losses due to remoteness of facilities and distances between facilities and markets are significant, and there is a limited market for the power domestically (there are few energy intensive industries in the province).

Province of Manitoba

The Province of Manitoba's ("the Province") long-term rating is confirmed at "A" with a Stable trend. The Province's rating continues to be supported by: (1) responsible fiscal management practices; (2) a slowly improving debt-to-GDP ratio; (3) continued efforts to enhance transparency and accountability; and (4) a stable and more diversified economy, which should help the Province weather the current period of economic uncertainty.

The Province's economy fared well in 2000, stimulated by strong external demand, robust business investments and consumer confidence. This translated into a 3.5% real GDP growth and a DBRS-adjusted surplus of $420 million, significantly better than the original surplus estimate of $132 million. Fiscal results are projected to weaken in 2001-02, however, as slower revenue growth, weaker Crown corporation earnings and continued spending pressures combine to lead to a projected DBRS-adjusted surplus of $17 million. With the U.S. economy gearing down rapidly and consumer confidence losing its momentum, growth is projected to decelerate in 2001, virtually eliminating the chances of a revenue windfall in most provinces. Due to its below-average dependence on foreign markets and a relatively high exposure to the stable services sector, however, Manitoba may be more successful than others at keeping its economy trending upwards in 2001. Despite the expected increase in the Province's debt level, the debt to GDP ratio is forecast to fall 0.6 percentage point to 38.4% (DBRS-adjusted) in 2001-02 due to the continued, though weaker, economic growth.

Nevertheless, challenges remain. The Province is highly dependent on federal transfers, which continue to account for more than 30% of total DBRS-adjusted revenue. This exposes fiscal results to fluctuations in the economic conditions of the "have" provinces and to changes in federal government transfer policies. In addition, the Province must deal with large unfunded pension liabilities and with important pressures in its health care sector, which is consuming a growing part of its budget.

The Manitoba Hydro-Electric Board

Balance Sheet
($ millions)

Assets	2001	2000	1999	Liabilities & Equity	2001	2000	1999
	As at March 31				As at March 31		
Cash + equivalents	0	15	58	Short-term debt	212	0	241
Accounts receivable	465	232	167	Long-term debt due 1 yr.	435	159	0
Accrued + prepaid	75	97	77	A/P + accrued	286	266	206
Current assets	540	344	301	Current liabilities	933	425	447
Net fixed assets	6,428	6,235	5,774	Long-term debt	6,020	6,611	5,883
Deferred debt costs & assets	402	406	311	Def'd + other liab	254	205	234
Pension assets	443	425	369	Pension obligation	386	358	369
Sinking funds	1,149	1,282	1,111	Contributions	281	275	267
				Reserves	1,088	818	666
Total	8,962	8,692	7,866	Total	8,962	8,692	7,866

Ratio Analysis

For years ended March 31	2001	2000	1999	1998	1997	1996	1995	1994
Liquidity Ratios								
Current ratio	0.58	0.81	0.67	0.65	0.26	0.38	0.47	0.94
Accumulated depreciation/gross fixed assets	28.9%	27.7%	27.7%	26.8%	25.8%	25.1%	24.1%	22.9%
Cash flow/total debt (1)	0.08	0.06	0.06	0.06	0.06	0.05	0.04	0.05
Cash flow/capital expenditures (2)	1.43	1.15	0.98	1.35	1.03	1.00	1.03	0.94
% debt in the capital structure (1)	85.3%	88.1%	89.5%	90.8%	92.4%	93.8%	95.0%	96.1%
Average coupon on long-term debt	8.31%	8.38%	8.56%	8.79%	8.74%	9.22%	8.49%	8.41%
Common equity in capital structure (1)	14.7%	11.9%	10.5%	9.2%	7.6%	6.2%	5.0%	3.9%
Coverage Ratios (3)								
EBIT interest coverage	1.53	1.31	1.19	1.22	1.21	1.15	1.13	1.12
EBITDA interest coverage	2.04	1.79	1.61	1.62	1.59	1.52	1.48	1.45
Fixed-charges coverage	1.53	1.31	1.19	1.22	1.21	1.15	1.13	1.12
Earnings Quality / Operating Efficiency								
Power purchases/revenues	2.2%	1.5%	3.5%	0.5%	0.6%	0.7%	0.3%	1.2%
Fuel costs/revenues	1.3%	1.2%	1.9%	0.8%	0.7%	0.7%	0.8%	0.8%
Operating margin	45.9%	43.4%	44.5%	48.2%	48.4%	47.9%	48.6%	49.8%
Net margin (before extras.)	19.4%	12.6%	9.3%	10.6%	9.9%	7.1%	5.9%	7.6%
Return on avg. equity (before extras.)	28.3%	20.5%	16.3%	21.6%	25.0%	22.0%	21.8%	35.9%
Profit returned to government	38.4%	50.5%	54.6%	52.5%	53.1%	60.7%	62.8%	53.0%
Customers/employee	89	100	97	99	100	98	98	95
Growth in customer base	0.3%	0.8%	1.2%	0.7%	0.7%	0.6%	0.8%	0.8%
GWh sold/employee	6.3	6.6	6.7	7.4	7.0	6.4	6.1	6.0
Self Generation - Cost Structure (4)								
OM&A	1.03	1.05	0.86	0.72	0.81	0.88	0.91	0.90
Fuel	0.06	0.06	0.08	0.03	0.03	0.03	0.03	0.03
Variable costs	1.10	1.11	0.94	0.75	0.84	0.91	0.94	0.94
Government levies	0.60	0.60	0.46	0.42	0.42	0.43	0.39	0.33
Net interest expense	1.36	1.48	1.50	1.35	1.44	1.61	1.66	1.71
Total cash costs	3.06	3.19	2.90	2.52	2.70	2.95	3.00	2.98
Non-cash financial charges	(0.04)	(0.03)	(0.03)	(0.02)	(0.01)	(0.01)	0.01	(0.05)
Depreciation	0.89	0.88	0.76	0.65	0.65	0.67	0.67	0.65
Total costs	3.90	4.04	3.63	3.16	3.34	3.62	3.68	3.58
Purchased Power (cents per gross kWh purchased)	3.31	1.79	1.97	3.21	3.43	1.72	1.50	1.53

(1) Sinking fund assets netted from debt obligations. Includes FX translation adjustments for U.S. dollar debt and sinking fund assets, excludes customer contributions.
(2) Capital expenditures are net of customer contributions.
(3) Before capitalized interest, AFUDC and debt amortizations.
(4) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

Income Statements ($ millions)	For years ended March 31 2001	2000	1999	1998	1997	1996	1995
Residential	316.0	300.0	300.0	299.1	312.2	301.1	272.0
Commercial/Industrial	419.0	395.0	400.2	393.6	387.7	377.9	358.1
Winnipeg Hydro	46.0	42.0	48.0	46.0	49.9	56.1	54.1
Subtotal domestic	781.0	737.0	748.2	738.7	749.8	735.1	684.2
Exports - U.S.	371.0	286.0	279.8	278.9	252.7	237.1	241.8
- interprovincial	109.0	90.0	46.4	18.1	15.0	8.3	11.3
Subtotal exports	480.0	376.0	326.2	297.0	267.7	245.4	253.1
Total electricity revenues	1,261.0	1,113.0	1,074.4	1,035.7	1,017.5	980.5	937.3
Other revenues	12.0	11.0	7.2	5.4	5.1	4.1	3.6
Net gas revenues	120.0	87.0	0.0	0.0	0.0	0.0	0.0
Total revenues	1,393.0	1,211.0	1,081.6	1,041.1	1,022.6	984.6	940.9
Expenses:							
Operating & administration	289.0	271.0	222.8	211.4	223.0	222.0	219.1
Power purchases	30.0	18.0	38.2	5.4	5.8	6.9	3.0
Fuel costs	18.0	15.0	20.6	8.8	7.0	7.3	7.4
Depreciation	249.0	227.0	198.0	191.0	177.4	168.5	159.8
Water rentals	56.0	51.0	50.5	55.8	51.3	47.1	45.2
Government guarantee fee	51.0	46.0	31.4	28.8	26.5	25.3	26.9
Taxes	61.0	58.0	38.6	37.7	36.7	35.9	22.1
Total operating costs	754.0	686.0	600.1	538.9	527.7	513.0	483.5
Operating income	639.0	525.0	481.5	502.2	494.9	471.6	457.4
Interest expense	489.0	468.0	474.9	476.7	472.1	454.4	454.1
Non-cash financial charges	(12.0)	(9.0)	(9.0)	(4.7)	(1.5)	(2.1)	2.1
Other (income)/expense	(108.0)	(86.0)	(84.5)	(80.3)	(76.8)	(50.8)	(54.7)
Net interest expenses	369.0	373.0	381.4	391.7	393.8	401.5	401.5
Pre-tax income	270.0	152.0	100.1	110.5	101.1	70.1	55.9
Operating Cash Flow	519.0	379.0	325.2	334.1	306.5	271.2	240.5
Less: capital expenditures (net of contrib.)	362.0	330.0	331.6	248.1	297.1	271.2	232.6
Cash flow before working capital	157.0	49.0	(6.4)	86.0	9.4	0.0	7.9
Less: working capital	185.0	5.0	(40.6)	37.4	33.6	5.9	0.4
Free cash flow	(28.0)	44.0	34.2	48.6	(24.2)	(5.9)	7.5
Less: other investments	40.0	348.0	44.8	(34.7)	80.3	28.8	29.1
Plus: net financing	51.0	262.0	(65.5)	(57.3)	178.1	68.2	(283.4)
Net change in cash flows	(17.0)	(42.0)	(76.1)	26.0	73.6	33.5	(305.0)
Unit Revenues and Costs							
Residential	5.98	6.09	6.06	6.06	5.85	5.69	5.67
Commercial/industrial	4.22	4.18	4.14	4.17	4.23	4.23	4.24
Winnipeg Hydro (net transfer)	3.21	3.00	2.85	3.01	3.18	3.55	3.64
Provincial Revenues	4.69	4.67	4.59	4.65	4.67	4.65	4.64
Export revenues - domestic	3.68	3.58	3.08	1.44	1.29	1.16	1.73
- U.S.	4.03	3.41	2.83	2.27	2.45	2.65	2.76
Total export revenues	3.95	3.45	2.86	2.19	2.33	2.54	2.69
Average electricity revenues	4.38	4.17	3.88	3.52	3.69	3.85	3.88
Ancillary revenues	0.46	0.37	0.03	0.02	0.02	0.02	0.01
Average revenues	4.84	4.54	3.91	3.53	3.71	3.87	3.89
Costs:							
Operations & administration	1.00	1.02	0.80	0.72	0.81	0.87	0.91
Power purchases	0.10	0.07	0.14	0.02	0.02	0.03	0.01
Fuel	0.06	0.06	0.07	0.03	0.03	0.03	0.03
Variable costs	1.17	1.14	1.02	0.77	0.86	0.93	0.95
Government levies	0.58	0.58	0.44	0.42	0.42	0.43	0.39
Net interest expense	1.32	1.43	1.41	1.35	1.43	1.59	1.65
Cash costs	3.08	3.15	2.86	2.53	2.70	2.94	2.99
Cash margin	1.76	1.39	1.04	1.01	1.00	0.93	0.90
Non-cash financial charges	(0.04)	(0.03)	(0.03)	(0.02)	(0.01)	(0.01)	0.01
Depreciation	0.86	0.85	0.72	0.65	0.64	0.66	0.66
Pre-tax margin	0.94	0.57	0.36	0.38	0.37	0.28	0.23
Variable costs	1.17	1.14	1.02	0.77	0.86	0.93	0.95
Fixed costs (deprec., int. + levies)	2.73	2.83	2.53	2.39	2.49	2.66	2.71
Total costs	3.90	3.97	3.54	3.16	3.34	3.59	3.66

Operating Statistics (millions kWh)

		For years ended March 31						
Electricity Sold - Breakdown		2001	2000	1999	1998	1997	1996	1995
Residential		5,282	4,928	4,947	4,937	5,340	5,288	4,800
Commercial/industrial		9,939	9,448	9,657	9,430	9,159	8,931	8,454
Winnipeg Hydro (net transfer)		1,431	1,401	1,684	1,528	1,569	1,582	1,486
Total Manitoba		16,652	15,777	16,288	15,895	16,068	15,801	14,740
Export sales - domestic		2,958.0	2,513	1,508	1,261	1,167	713	653
- U.S.		9,196.0	8,398	9,896	12,306	10,332	8,946	8,772
Total exports		12,154	10,911	11,404	13,567	11,499	9,659	9,425
Total sold		28,806	26,688	27,692	29,462	27,567	25,460	24,165
Energy sales growth		7.9%	-3.6%	-6.0%	6.9%	8.3%	5.4%	0.3%
Generation								
Available from Winnipeg Hydro		139	133	134	134	140	140	140
Hydro	95.3%	4,840	4,750	4,767	4,767	4,834	4,834	4,834
Gas	4.5%	231	233	236	236	237	369	369
Oil	0.2%	9	8	11	15	20	20	18
Installed capacity (MW)		5,080	4,991	5,014	5,018	5,091	5,223	5,221
Energy cenerated (millions kWh)								
Hydro		30,697	28,360	28,303	32,806	30,711	28,129	26,932
Coal + oil		870	684	949	301	198	228	236
Gross energy generated	96.7%	31,567	29,044	29,252	33,107	30,909	28,357	27,168
Plus: net power exchange		905	1,004	1,935	168	169	401	200
Energy generated + purchased		32,472	30,048	31,187	33,275	31,078	28,758	27,368
Less: transmission losses + internal use		3,666.0	3,360	3,495	3,813	3,511	3,298	3,203
Total sold		28,806	26,688	27,692	29,462	27,567	25,460	24,165
Energy lost + used/energy gen. + purch.		11.3%	11.2%	11.2%	11.5%	11.3%	11.5%	11.7%
Peak demand (MW)		3,636.0	3,524	3,559	3,490	3,409	3,588	3,268
Peak demand/installed capacity		71.6%	70.6%	71.0%	69.5%	67.0%	68.7%	62.6%
Export Interconnections								
Ontario Hydro		263	240	240	240	240	240	240
Saskatchewan Power		450	450	450	300	300	300	300
U.S. - MAPP		2,050	2,050	2,050	1,900	1,900	1,900	1,900
Total (MW)		2,763	2,740	2,740	2,440	2,440	2,440	2,440
Interconnections as a % of installed capacity		54.4%	54.9%	54.6%	48.6%	47.9%	46.7%	46.7%

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.)

Current Report: September 18, 2001
Previous Report: September 29, 2000

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RATING*

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Corporate Long-term Debt

RATING HISTORY

	Current	2000	1999	1998	1997	1996	1995
Corporate Long-term Debt	"A"	"A"	"A"	"A"	"A"	"A"	"A"

UPDATE

DBRS confirms the corporate long-term debt of New Brunswick Power Corporation ("NB Power" or "the Utility")at "A" with a Stable trend. The rating is a flow-through of the rating of the Province of New Brunswick, which conducts all of the Utility's financing activities. NB Power reported a net loss of $12 million (compared to an income of $17 million in the previous year), despite achieving revenues in F2000 which were 4.9% higher than in F1999. The net loss is attributed to a six-week unplanned outage at the Point Lepreau nuclear generating station, lost export sales opportunities and one-time charges. NB Power is well positioned geographically to wheel and/or export electricity to the U.S. northeast. Over the near to mid-term, exports should continue to make a strong contribution to earnings and cash flows. While NB Power's rates are above average in comparison to other Canadian utilities, partially due to the thermal-based nature of generating capacity, the variable costs of Cdn3.9¢ per kWh allows NB Power to compete effectively in the New England region where electricity prices range between US8.7¢ - US15.9¢ per kWh. Competitive pressures are expected to develop over the longer term, however, in both domestic and export markets, as the gas distribution networks expand. Key debt ratios are currently weak, partially due to the F1998 $450 million write-down of Lepreau nuclear station. With annual maintenance capital expenditures in the $100 million - $110 million range and no dividend requirements, NB Power should generate substantial cash flow surpluses assuming the Lepreau nuclear station is operating relatively problem free. Debt ratios should slowly improve, but will be influenced over the longer term by a number of major capital projects currently in the development stage, including the potential refurbishment of the 635-MW Lepreau nuclear station. The refurbishment, which will be required as early as F2006 to extend the life of the plant, is expected to cost between $600 million - $700 million.

CONSIDERATIONS

Strengths:

- Debt guaranteed by provincial government
- Surplus cash flows available for debt reduction
- Well positioned geographically to wheel/export power to U.S.
- Low costs relative to electricity generators in Northeastern U.S.
- Relatively favourable regulatory environment
- Fuel source conversions will reduce costs and emissions

Challenges:

- Ongoing problems with Lepreau nuclear generator
- Excessively high debt levels, weak profitability
- High foreign exchange exposure
- Sable Island gas a growing competitive threat; domestic and exports markets in the U.S.
- Future environmental concerns, given heavy reliance on thermal-based generation.
- Wholesale competition begins in April 2003

FINANCIAL INFORMATION

For years ended March 31	2001	2000	1999	1998	1997	1996	1995
EBIT interest coverage (times)	1.05	1.12	1.13	0.92	0.79	0.74	0.81
Net debt in capital structure	99.7%	99.3%	99.9%	88.6%	88.3%	88.0%	88.0%
Cash flow/total debt (times)	0.07	0.08	0.08	0.05	0.04	0.04	0.04
Cash flow/capital expenditures (times)	1.81	2.49	3.68	2.61	1.72	0.75	0.90
Net income (before transfers/extras.) ($ millions)	0	24	18	(43)	(83)	(109)	(58)
Operating cash flow ($ millions)	214	237	239	154	119	123	144
Electricity sales (millions of kWhs)	18,889	19,842	20,597	18,577	16,805	17,337	16,361
Electricity revenues (cents per kWh sold)	6.69	6.14	5.71	5.99	5.99	5.70	5.59
Variable costs (cents per net gen kWh sold)	3.93	3.23	2.85	3.25	3.35	3.83	2.98
Fixed costs (cents per net gen kWh sold)	3.19	3.55	3.10	3.52	4.19	4.54	3.97
Average coupon on long-term debt	8.39%	8.88%	9.07%	9.06%	9.07%	9.13%	9.20%

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.

Regulation

NB Power is regulated by the Board of Commissioners of Public Utilities ("PUB") 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 far below what regulated utilities in the private sector are allowed to earn.

Considerations

Strengths: (1) NB Power's debt securities are the direct obligations of the provincial government. As a result, the rating of NB Power is a flow-through of the rating of the Province of New Brunswick.
(2) NB Power is generating surplus cash flows, well in excess of maintenance capital expenditures, and is not required to pay a dividend to the Province.
(3) NB Power is in a good position to wheel and/or export power to markets in the U.S. NB Power's interconnections include 1,060 MW with Hydro-Québec, 500 MW with Nova Scotia Power, 200 MW with Maritime Electric and 810 MW with New England, which represent about 68% of installed capacity. The high interconnections provide NB Power with operating flexibility to meet the energy demands of its own customers, as well as incremental earnings from wheeling and/or electricity exports.
(4) NB Power's variable costs of Cdn3.9¢ per kWh compare favourably relative to electricity generators in the U.S. northeast, NB Power's primary export market. Electricity prices in the U.S. northeast are among the highest in North America and range between US8.7¢ - US15.9¢ per kWh.
(5) The regulatory environment is relatively favourable. NB Power can raise rates by up to 3%, or the CPI rate (whichever is higher), without requiring lengthy hearings and regulatory approval. A 3.0% rate increase was implemented April 1, 2000. Rate rebalancing among the commercial and residential customer classes is needed to bring rates in line with the cost of delivered service.
(6) Conversion of oil- and/or coal-based plants to lower cost fuels or dual energy facilities should help to materially reduce costs and emissions in the future. The Bayside Power Project currently underway is being financed through a partnership, which will eliminate any balance sheet pressures. The refueling (from oil) of Courtenay Bay into a 280-MW natural gas combined cycle unit should be commissioned by October 2001. NB Power has contracted to buy the winter capacity from the Project at its avoided cost, while partner Westcoast Energy Inc. will bear the risk of marketing the summer capacity.

Challenges: (1) The Lepreau nuclear generator continues to represent a future challenge for NB Power. (a) The station continues to experience a wide range of problems relating to pressure tubes and feeder pipes. There were two unscheduled outages during 2000-2001, totalling six weeks, to replace an electrical generator seal and three feeder pipes. This resulted in a fiscal year capacity factor of 65.1%, less than the budgeted capacity factor of 72%. In addition, a major refurbishment, at an estimated cost of about $600 million - $700 million, will be required by F2006. (b) Accounting reserves of $221 million have been recorded to date to finance the decommissioning of nuclear facilities and the disposal of waste fuels, but no cash funds have been set aside to meet this future obligation. This is in contrast to U.S. nuclear operators, which establish cash reserves. In addition, given the uncertainties associated with nuclear waste disposal technology, it is difficult to assess whether these reserves will be sufficient.
(2) Excessively high debt levels contribute to consistently weak profitability and key debt ratios. The $450 million write-down of Lepreau in F1998 substantially increased balance sheet leverage to 100% in F1998 from 89% in F1997.
(3) With 33% of outstanding long-term debt denominated in U.S. dollars, NB Power is sensitive to changes in the U.S. dollar/Canadian dollar exchange rate. This sensitivity is exacerbated by the utility's reliance on thermal-based generating capacity as fuels are priced in U.S. dollars. The exposure is partially hedged by U.S. dollar revenues and is managed with currency hedges. The 2000-01 foreign exchange adjustment was minus $82 million, compared to $37 million in the previous fiscal year.
(4) Sable Island gas represents a growing competitive threat in both domestic and export markets as the distribution infrastructures are developed. The gas exported to the U.S. northeast is presently being used primarily by electricity generators who are competing with NB Power.
(5) Given its heavy reliance on thermal-based generation (60% of installed capacity), NB Power must contend with future environmental concerns. Presently, the locally sourced coal and heavy oil used by NB Power has a relatively high sulfur content. Emissions of SO_2 will be sharply reduced over the next few years as NB Power has announced that it will close its 57 MW Grand Lake coal-based plant by 2004, and one 100 MW oil-fired unit (Courtenay Bay) will be converted into a 280-MW combined cycle facility that will displace higher cost thermal generated energy.
(6) Wholesale competition in New Brunswick is scheduled to begin in April 2003. This will present an operational challenge to NB Power in that the Utility must budget to supply power to all of its existing customers, while it is probable that some large industrial customers may chose to purchase electricity generated from an entity other than NB Power.

EARNINGS

($ millions)	2001	2000	1999	1998	1997	1996	1995
	For years ended March 31						
Revenues (1)	1,309.0	1,248.0	1,204.0	1,140.4	1,037.1	1,018.1	942.3
EBITDA	517.0	553.0	567.0	486.9	461.4	412.0	453.3
EBIT	312.0	363.0	378.0	309.8	277.4	269.0	293.2
Net interest expense	296.0	324.0	335.0	338.0	349.5	365.8	360.6
Net income before extras	0.0	24.0	18.0	(43.1)	(83.1)	(109.1)	(58.4)
Net income	(12.0)	17.0	(423.0)	(21.2)	(19.4)	8.2	25.7

(1) Includes non-energy revenues.

Operating income (DBRS-adjusted) decreased by 14.1% in 2000-01 to $312 million from the previous fiscal year, and net income dropped to ($12) from $17. The weaker performance is due to the following factors. (1) A six-week unplanned outage at the Point Lepreau nuclear generating station, which began late in the fiscal year and lasted 27 days in 2000-01, cost NB Power $27 million in expenses and lost export sales. (2) Lower water flows lead to hydro production that was 11% lower than the long-term average. (3) Total fuel costs in 2000-01 were 78.2% higher at $401 million - due to lower hydro and nuclear generation, higher oil prices and a lower Canadian dollar. (4) Less electricity was available for export due to the lower-than-average hydro performance and reduced capacity from Point Lepreau. (5) NB Power recorded a one-time charge of $5 million for early retirement costs due to staff reduction at NB Coal Limited and a $7 million one-time write-down for a surplus dragline. NB Power was able to reduce costs in the following areas: (1) Finance charges decreased by $25 million to $306 million in 2000-01 primarily because of a reduction in net debt in the previous year and refinancing at lower interest rates. (2) The cost of purchased power was 41.1% lower in 2000-01 since a fixed price contract with a neighbouring utility expired in February 2000.

Outlook: Exports should continue to make a strong contribution to earnings over the short-term. Electricity prices in the U.S. northeast are among the highest in North America (range US8.7¢ - US15.9¢ per kWh), so with variable costs of Cdn3.9¢ per kWh, NB Power remains very competitive. However, over the longer term NB Power will face competitive pressures in the New England markets as natural gas becomes more readily available as an alternative source of energy, and new plants currently under construction become operational. The latest fiscal results have demonstrated that NB Power's profitability is not sufficient to absorb the unplanned loss of generation at Point Lepreau for an extended period, as the station provides up to 30% of the Utility's generation capacity. NB Power's performance will remain sensitive until station refurbishment is undertaken or decommissioned. A decision on whether to proceed with the major refurbishment will be made by the end of 2001-02. The project would likely start in F2003 and involve an 18 to 24-month shutdown of the plant commencing in F2006. Earnings over the period will likely be adversely affected by higher external power purchased power costs to replace power generated by Lepreau.

NB Power's exposure to oil price fluctuations has been minimized by diversifying fuel sources. In 2000-01 natural gas will be added to the NB Power's generation sources.

REVENUES

Customer Sector	Revenues - $ millions 2001	2000	1999	Energy Sales - millions of kWh 2001	2000	1999	Unit Revenues - cents/kWh sold 2001	2000	1999
Wholesale	73	71	68	1,171	1,126	1,069	6.23	6.31	6.36
Industrial	298	288	283	6,068	5,924	5,985	4.91	4.86	4.73
General service/commercial	178	176	170	2,111	2,093	2,036	8.43	8.41	8.35
Residential	364	340	335	4,587	4,371	4,387	7.94	7.78	7.64
Street lights	18	13	16	74	73	72	24.32	17.81	22.22
Total domestic	931	888	872	14,011	13,587	13,549	6.64	6.54	6.44
Exports	332	330	304	4,878	6,255	7,048	6.81	5.28	4.31
Total sold	1,263	1,218	1,176	18,889	19,842	20,597	6.69	6.14	5.71
Annual change	3.7%	3.6%	5.6%	-4.8%	-3.7%	10.9%			

While domestic energy sales increased 3.1% to 14,011 million kWh, exports dropped 22.0% to 4,878 million kWh, resulting in a 4.8% drop in overall energy sales to 18,889 million kWh. Domestic sales improved due to colder weather, which increased consumption by 484 million kWh, and higher industrial sales of 139 million kWh from a strong economy. Despite the overall drop in energy sales, energy revenues increased for two reasons: (1) a 3% residential rate increase on April 1, 2000, and (2) higher export prices of 6.8¢ per kWh compared to 5.3¢ per kWh last year, which helped offset the decreased volume of energy exported.

FINANCIAL PROFILE & SENSITIVITY ANALYSIS

Years ending Mar. 31	Actual		Stress Testing		
Cash Flow Statement	2001	2000	Year 1	Year 2	Year 3
Net income (before extras)	0.0	24.0	(0.7)	11.9	25.0
Depreciation	205.0	190.0	167.4	163.4	159.7
Other non-cash adjustments	9.0	23.0	15.0	15.0	15.0
Operating cash flow	214.0	237.0	181.8	190.3	199.7
Plus: dividends received	0.0	0.0	0.0	0.0	0.0
Less: common dividends	0.0	0.0	0.0	0.0	0.0
Less: capital expenditures (net of contrib)	118.0	95.0	100.0	100.0	100.0
Gross free cash flow	96.0	142.0	81.8	90.3	99.7
Less: working capital changes	(16.0)	(22.0)	0.0	0.0	0.0
Free cash flow	112.0	164.0	81.8	90.3	99.7
Less: other investments	(2.0)	(33.0)	0.0	0.0	0.0
Plus: net financing	(91.0)	(170.0)	0.0	0.0	0.0
Net change in cash	23.0	27.0	81.8	90.3	99.7
Change in net debt	0.0	(207.0)	(81.8)	(90.3)	(99.7)
% Debt in capital structure (1)	99.7%	99.3%	99.7%	99.3%	98.4%
EBIT interest coverage	1.05	1.12	1.05	1.09	1.14
Cash flow/ total debt (1)	0.07	0.08	0.06	0.07	0.07

(1) Debt is net of sinking fund assets.

Financial Profile:

Despite reporting a net loss (after one-time charges) in 2000-01, NB Power generated sufficient cash from operations to cover its capital expenditures of $118 million. Net debt remained constant year-over-year at $2,971 million, compared to a $207 million reduction in 1999-2000. The level of debt reduction was significantly affected by the amount of U.S. denominated debt (approximately 33% of its debt portfolio) and the decline in the value of the Canadian dollar. Before the foreign exchange adjustment at fiscal year end, debt reduction was $105 million. NB Power has initiated a long-term plan to rollover U.S. dollar debt into Canadian funds, as well as implemented a currency hedging program to mitigate the impact of currency fluctuations. During 2000-01, 88% of the Utility's U.S. dollar requirement was hedged.

Despite continued efforts to reduce debt, the debt-to-capital ratio remains high at 99.7% compared to investor-owned utilities, typically in the area of 55%. Similarly, EBIT interest coverage remains weak at 1.05 times compared to the 2.5 to 3.0 times typical of the private sector. However, since it is a Crown corporation, NB Power faces certain restrictions that investor-owned utilities do not face, such as the lack of access to equity markets. Furthermore, given that its sole shareholder is the New Brunswick government, which has non-financial objectives, its dividend payout structure can be significantly different from investor-owned utilities. As such, its capital structure and other financial ratios may not necessarily be the same as those of investor-owned utilities.

Outlook: Over the longer term, financial leverage may come under pressure due to three potential projects that NB Power has identified. (1) A second 345 kV transmission and interconnection to New England is to be constructed in 2003, to increase import and export opportunities. NB Power would be responsible for financing the Canadian segment at about $45 million. (2) The Lepreau nuclear plant is nearing the end of its useful life (2006), and the cost of refurbishment will be in the $600 million - $700 million range. The Utility could proceed with the project under a joint venture, which would ease the strain on the balance sheet. (3) The 1,004-MW oil-fired Coleson Cove plant may be converted to orimulsion in order to meet new environmental regulations. While this would not add any additional capacity, it would allow the facility to run at a higher capacity factor. The excess power generated during the summer could be sold into export markets. This conversion is expected to cost $600 million - $700 million. The conversion will begin during the summer of 2003 and be completed and on-line by 2005. This project could also proceed under a joint venture arrangement. The preliminary engineering and assessment program is currently underway, a final decision on these projects is expected by the end of 2001-02.

Sensitivity Analysis:

Stress Testing: The assumptions used in the test below are not based on any information by the Utility, or DBRS expectations. Their use is solely to measure the credit strength of the Utility under specific conditions. Assumptions: A 5% decrease in EBITDA in Year 1 and remains level in Years 2 and 3, capital expenditures are held at $100 million over the next few years – in line with recent years.

In the scenario shown above, the Utility would be able to generate free cash of $80 million to $100 million per year, which could be used to pay down debt and contribute to a slow improvement in key debt ratios. Alternatively, the excess cash could be retained and used to partially fund the refurbishment of the Lepreau nuclear plant and/or the Coleson Cove conversion. This stress test clearly indicates that NB Power will not generate sufficient cash flow to fund these projects independently. Either the Utility will have to increase its already high debt levels or enter joint venture agreements in order to proceed with these projects.

OPERATING LINES OF CREDIT

NB Power has bank lines of credit, with Canadian banks, for short-term borrowings totaling $104 million. These lines of credit are payable upon demand and are guaranteed by the Province of New Brunswick. NB Power also borrows funds for temporary purposes directly from the Province of New Brunswick. The short-term borrowings from the Province were $102 million at March 31, 2001.

DEBT MATURITY SCHEDULE (years ending March 31)

	2002	2003	2004	2005	2006
($millions)	250	689	100	0	200

WHITE PAPER – NEW BRUNSWICK ENERGY POLICY 2000-2010

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 be achieved by introducing wholesale competition and allowing non-utility generation and retail competition for large industrial customers by April 2003, while waiting until conditions prove more favourable before permitting full retail competition.

Wholesale Competition: One of the major challenges to achieving a workable competitive wholesale market is the limited size of the New Brunswick market. To achieve a workably competitive market within New Brunswick either the Crown utility's generation portfolio must be broken up or the Province's transmission interconnections with adjacent markets must be significantly increased. However, breaking up the NB Power's generation portfolio risks sacrificing its economies of scale, which could result in higher costs for consumers. The following are some of the key guidelines outlined in the provincial policy to address these challenges. (1) The Crown utility is directed to increase interconnection into the greater Northeast power market and pursue the formation of a regional transmission organization (RTO) to enhance access to neighbouring jurisdictions. (2) The economic advantage of retaining economies of scale afforded to the relatively small Crown utility make functional unbundling (i.e., separation of transmission and generation functions) a preferred option over structural separation (i.e., three separate crown corporations: generation; transmission; and distribution). (3) The Province will examine the issue of "leveling the playing field" between the Crown corporation and other market participants to ensure that this does not impede the development of a competitive wholesale market. (4) The Province will permit the distribution electric utilities to procure power in the competitive market by a target date of April, 2003. (5) The Province will allow no new distribution electric utilities in New Brunswick and limit existing ones to their current service territories in order to avoid higher overall costs due to loss of economies of scale.

Non-Utility Generation Development: The Province will remove current restrictions on the construction of generation facilities.

Full Retail Competition: The government's approach to full retail competition is to stage implementation starting with large industrial customers in April 2003, and revisiting the merits of introducing retail competition for smaller customers every two years or following pre-specified events.

PROVINCE OF NEW BRUNSWICK

The Province of New Brunswick's (the "Province") long-term rating is confirmed at "A", with a Stable trend. The rating reflects: (1) the Province's track record of prudent fiscal management; (2) a more diversified economic base; (3) improved efficiency in government operations; and (4) low and declining pension plan obligations.

Stronger than expected economic growth allowed the Province to post a DBRS-adjusted surplus of $133 million, significantly above the $21 million originally forecast. For 2001-02, the Province projects another surplus of $35 million. With the U.S. economy gearing down and several major local construction projects now completed, however, New Brunswick's economy will likely be growing at a much slower pace than in the last three years, suggesting a lower possibility of another important revenue windfall.

Despite sound fiscal management, the debt level of the Province has been rising markedly in recent years, primarily due to non-budgetary items and capitalized interest on the Fredericton-Moncton Highway debt. Although sustained economic growth has improved the Province's capacity to bear debt, the debt to GDP ratio is still moderately high as progress in reducing it remains slow. In 2001-02, the positive impact of continued economic growth on the Province's ratio is expected to be offset by an estimated $266 million increase in total debt (unfunded pension liabilities plus net tax-supported debt), leaving the ratio fairly stable at 34.5%. Maintaining the downward trend in the debt-to-GDP ratio may prove to be a challenge for the Province, especially in a period of weakening economic growth.

In addition, the Province must deal with the volatility associated with its relatively high dependence on federal transfers and on cyclical industries (mostly resource-based), and with below-average population growth, which constitutes an impediment to long-term economic growth.

New Brunswick Power Corporation

Balance Sheet

($ millions)

	As at March 31				As at March 31		
Assets	2001	2000	1999	**Liabilities & Equity**	2001	2000	1999
Cash + equivalents	57	34	7	Short-term debt	102	176	159
Accounts receivable	174	170	191	Accounts payable	164	139	128
Material, supplies + fuel	78	78	74	Accrued interest	73	79	84
Prepaid expenses	4	3	3	Long-term debt due 1 yr	245	234	130
Current assets	313	285	275	Current liabilities	584	628	501
Net fixed assets	2,906	2,997	3,130	Long-term debt	2,624	2,578	2,945
Deferred charges + other assets	251	166	205	Deferred liabilities	254	239	218
Sinking fund investments	0	17	56	Shareholders equity	8	20	2
Total	3,470	3,465	3,666	Total	3,470	3,465	3,666

Ratio Analysis

	For years ended March 31							
Liquidity Ratios (1)	2001	2000	1999	1998	1997	1996	1995	1994
Current ratio	0.54	0.45	0.55	0.56	0.62	0.68	0.53	0.69
Accumulated depreciation/gross fixed assets	45.4%	42.8%	40.0%	37.2%	31.6%	29.0%	27.2%	25.3%
Cash flow/total debt	0.07	0.08	0.08	0.05	0.04	0.04	0.04	0.05
Cash flow/capital expenditures (2)	1.81	2.49	3.68	2.61	1.72	0.75	0.90	0.59
% debt in capital structure	99.7%	99.3%	99.9%	88.6%	88.3%	88.0%	88.0%	88.4%
Average coupon on long-term debt	8.39%	8.88%	9.07%	9.06%	9.07%	9.13%	9.20%	9.20%
Common equity in capital structure	0.3%	0.7%	0.1%	11.4%	11.7%	12.0%	12.0%	11.6%
Common dividend payout (before transfers)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (3)								
EBIT interest coverage	1.05	1.12	1.13	0.92	0.79	0.74	0.81	0.91
EBITDA interest coverage	1.75	1.71	1.69	1.44	1.32	1.13	1.26	1.28
Fixed-charges coverage	1.05	1.12	1.13	0.92	0.79	0.74	0.81	0.91
Earnings Quality / Operating Efficiency								
Power purchases/revenues	7.6%	13.6%	8.1%	10.6%	11.3%	14.7%	9.1%	6.1%
Fuel costs/revenues	30.6%	18.0%	22.9%	24.9%	20.7%	20.4%	16.0%	16.1%
Operating margin	21.9%	26.8%	28.5%	24.5%	22.8%	22.2%	26.9%	30.8%
Net margin (bef transfers, extras.)	0.0%	1.9%	1.5%	-3.8%	-8.0%	-10.7%	-6.2%	5.6%
Return on avg. equity (bef transfers, extras.)	0.0%	218.2%	8.4%	-9.9%	-18.2%	-23.6%	-13.1%	12.0%
Profit returned to gov't (bef transfers, extras.)	100.0%	68.0%	66.1%	166.3%	139.4%	361.0%	63.6%	48.4%
Customers/employee	136	133	131	131	129	125	117	114
Growth in customer base	0.9%	1.9%	0.6%	0.7%	0.7%	0.8%	1.4%	1.4%
GWh sold/employee	7.2	7.5	7.8	7.1	6.4	6.4	5.7	5.2
Self Generation - Cost Structure (4)	(cents per net generated kWh sold) (Tables may not add due to rounding)							
OM&A	1.57	1.78	1.34	1.44	1.74	2.05	1.84	1.83
Fuel	2.36	1.45	1.51	1.81	1.62	1.78	1.14	1.09
Variable costs	3.93	3.23	2.85	3.25	3.35	3.83	2.98	2.92
Gov't levies	0.29	0.33	0.29	0.34	0.40	0.45	0.38	0.36
Net interest expense	1.59	1.90	1.64	1.96	2.32	2.77	2.44	2.32
Total cash costs	5.81	5.46	4.79	5.54	6.08	7.04	5.80	5.60
Non-cash financial charges	0.09	0.10	0.14	0.09	0.08	0.11	(0.07)	(0.62)
Depreciation	1.21	1.22	1.03	1.13	1.38	1.22	1.22	0.98
Total costs	7.11	6.77	5.96	6.77	7.54	8.37	6.95	5.96
Purchased power (cents per gross kWh purch.)	4.78	3.61	3.82	3.83	3.00	2.38	2.42	2.66

(1) All debt ratios are net of sinking fund assets.

(2) Capital expenditures are net of customer contributions.

(3) Before capitalized interest, AFUDC and debt amortizations.

(4) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to energy supplied.

Income Statements

($ millions)	For years ending March 31 2001	2000	1999	1998	1997	1996	1995
Wholesale	73.0	71.0	68.0	69.4	68.9	67.3	65.0
Industrial	298.0	288.0	283.0	279.9	262.6	257.4	233.6
General service/commercial	178.0	176.0	170.0	168.2	162.9	158.2	148.9
Residential	364.0	340.0	335.0	335.6	315.5	303.3	289.1
Street lights	18.0	13.0	16.0	16.2	15.4	15.3	14.5
Subtotal domestic	931.0	888.0	872.0	869.3	825.3	801.5	751.1
Exports	332.0	330.0	304.0	244.3	181.6	186.9	164.1
Subtotal energy revenues	1,263.0	1,218.0	1,176.0	1,113.6	1,006.9	988.4	915.2
Non-energy revenues	46.0	30.0	28.0	26.8	30.2	29.7	27.2
Total revenues	1,309.0	1,248.0	1,204.0	1,140.4	1,037.1	1,018.1	942.3
Expenses:							
Operating & administration	266.5	276.9	245.4	226.8	230.9	239.2	241.6
Power purchases	100.0	170.0	98.0	120.5	117.3	149.2	86.1
Fuel costs	401.0	225.0	276.0	283.8	214.9	208.1	150.6
Depreciation & amortization	205.0	190.0	189.0	177.1	184.0	143.0	160.1
Municipal + property taxes	30.5	31.1	31.6	31.6	31.4	30.6	29.4
Debt guarantee fee	19.0	20.0	21.0	21.6	22.0	21.8	21.1
Total operating costs	1,022.0	913.0	861.0	861.4	800.5	792.0	688.9
Operating income	287.0	335.0	343.0	279.0	236.5	226.1	253.4
Interest expense	296.0	324.0	335.0	338.0	349.5	365.8	360.6
Non-cash financial charges	16.0	15.0	25.0	14.9	10.9	12.3	(9.1)
Other (income)/expense	(25.0)	(28.0)	(35.0)	(30.8)	(40.9)	(42.9)	(39.8)
Net interest expense	287.0	311.0	325.0	322.1	319.6	335.2	311.8
Income before transfers	0.0	24.0	18.0	(43.1)	(83.1)	(109.1)	(58.4)
Equalization/fuel channel transfers	0.0	0.0	9.0	21.9	68.0	71.2	87.3
Income before extraordinary items	0.0	24.0	27.0	(21.2)	(15.1)	(37.9)	28.9
Extraordinary items	12.0	7.0	450.0	0.0	4.3	(46.1)	3.1
Net income	(12.0)	17.0	(423.0)	(21.2)	(19.4)	8.2	25.7

($ millions)	For years ending March 31 2001	2000	1999	1998	1997	1996	1995
Operating cash flow	214.0	237.0	239.0	154.0	119.0	123.5	144.0
Capital expenditures (net of contrib.)	118.0	95.0	65.0	59.1	69.1	164.4	160.1
Cash flow before working capital	96.0	142.0	174.0	94.9	49.9	(40.9)	(16.1)
Less: working capital	(16.0)	(22.0)	(21.0)	25.3	(2.7)	11.2	29.2
Free cash flow	112.0	164.0	195.0	69.6	52.5	(52.1)	(45.3)
Less: other investments	(2.0)	(33.0)	14.0	11.5	0.0	0.0	0.0
Plus: net financing (incl. Short-term financing)	(91.0)	(170.0)	(186.0)	(83.5)	(70.0)	161.1	(83.2)
Net change in cash	23.0	27.0	(5.0)	(25.4)	(17.4)	109.0	(128.4)

		For years ending March 31						
Operating Statistics (millions kWh)		2001	2000	1999	1998	1997	1996	1995
Electricity Sold - Breakdown								
Wholesale		1,171	1,126	1,069	1,091	1,094	1,068	1,061
Industrial		6,068	5,924	5,985	6,003	5,604	5,620	5,170
General service/commercial		2,111	2,093	2,036	2,066	2,048	2,022	1,938
Residential		4,587	4,371	4,387	4,575	4,441	4,418	4,326
Street lights		74	73	72	71	70	69	69
Total domestic		14,011	13,587	13,549	13,806	13,256.7	13,197.5	12,564
Exports		4,878	6,255	7,048	4,771	3,547.7	4,140.4	3,797
Total - sold		18,889	19,842	20,597	18,577	16,805	17,337	16,361
Energy sales growth		-4.8%	-3.7%	10.9%	10.5%	-3.1%	6.0%	8.3%
Generation								
Hydro	23%	884	884	884	884	881	881	881
Nuclear	17%	635	635	635	635	635	635	635
Oil	38%	1,441	1,585	1,585	1,585	1,585	1,585	1,585
Orimulsion	8%	300	300	300	300	300	300	300
Coal	14%	515	515	515	515	508	508	508
Installed Capacity (MW)		3,775	3,919	3,919	3,919	3,909	3,909	3,909
Energy Generated (millions kWh)								
Hydro		2,373	3,018	2,696	2,357	2,859	2,731	2,797
Nuclear		3,899	4,323	4,970	3,962	3,777	1,703	5,593
Oil		6,081	3,257	5,982	4,687	2,268	2,816	2,975
Orimulsion		2,201	2,373	2,410	2,424	2,104	1,971	82
Coal		4,264	4,152	4,041	3,811	3,787	3,728	3,220
Gross energy generated	90%	18,818	17,123	20,099	17,242	14,795	12,950	14,667
Plus: purchases	10%	2,092	4,712	2,568	3,148	3,908	6,274	3,559
Energy generated + purchased		20,910	21,835	22,667	20,390	18,704	19,223	18,226
LESS: internal use		2,021	1,993	2,070	1,813	1,899	1,886	1,866
Total - sold		18,889	19,842	20,597	18,577	16,805	17,337	16,361
Energy lost + used/Energy gen + purch		9.7%	9.1%	9.1%	8.9%	10.2%	9.8%	10.2%
Peak demand - MW		2,893	2,856	2,786	2,792	2,832	2,826	2,790
Peak demand/Installed capacity		76.6%	72.9%	71.1%	71.2%	72.4%	72.3%	71.4%
Export Interconnections								
Hydro-Quebec		1,060	1,060	1,060	1,060	1,060	1,060	1,060
Nova Scotia Power Corp.		500	500	500	500	500	500	500
Maritime Electric Co. Ltd.		200	200	200	200	200	200	200
New England Utilities		810	810	810	810	810	810	810
Total - MW		2,570	2,570	2,570	2,570	2,570	2,570	2,570
Interconnections as a % of installed capacity		68.1%	65.6%	65.6%	65.6%	65.7%	65.7%	65.7%

Unit Revenues and Costs	(cents per kWh sold) (Tables may not add due to rounding)						
	2001	2000	1999	1998	1997	1996	1995
Wholesale	6.23	6.31	6.36	6.36	6.30	6.30	6.13
Industrial	4.91	4.86	4.73	4.66	4.69	4.58	4.52
General service/commercial	8.43	8.41	8.35	8.14	7.95	7.82	7.68
Residential	7.94	7.78	7.64	7.33	7.10	6.86	6.68
Street lights	24.32	17.81	22.22	22.85	22.17	22.32	21.07
Domestic revenues	6.64	6.54	6.44	6.30	6.23	6.07	5.98
Exports	6.81	5.28	4.31	5.12	5.12	4.51	4.32
Average electricity revenues	6.69	6.14	5.71	5.99	5.99	5.70	5.59
Ancillary revenues	0.24	0.15	0.14	0.14	0.18	0.17	0.17
Average revenues	6.93	6.29	5.85	6.14	6.17	5.87	5.76
Costs:							
Operating & administration	1.41	1.40	1.19	1.22	1.37	1.38	1.48
Purchased power	0.53	0.86	0.48	0.65	0.70	0.86	0.53
Fuel	2.12	1.13	1.34	1.53	1.28	1.20	0.92
Variable costs	4.06	3.39	3.01	3.40	3.35	3.44	2.92
Government levies	0.26	0.26	0.26	0.29	0.32	0.30	0.31
Net interest costs	1.43	1.49	1.46	1.65	1.84	1.86	1.96
Cash costs	5.76	5.14	4.72	5.34	5.51	5.61	5.19
Cash margin	1.17	1.15	1.13	0.80	0.67	0.27	0.57
Non-cash financial charges	0.08	0.08	0.12	0.08	0.07	0.07	(0.06)
Depreciation	1.07	0.94	0.90	0.94	1.08	0.80	0.97
Decommissioning	0.01	0.01	0.01	0.01	0.02	0.02	0.01
Pre-tax margin	(0.00)	0.12	0.09	(0.23)	(0.49)	(0.63)	(0.36)
Variable costs	4.06	3.39	3.01	3.40	3.35	3.44	2.92
Fixed costs (deprec, interest + taxes)	2.87	2.78	2.75	2.97	3.31	3.06	3.19
Total costs	6.93	6.17	5.76	6.37	6.67	6.50	6.12

Newfoundland and Labrador Hydro

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

Current Report: October 2, 2001
Previous Report: September 20, 2000

RATING

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Rating	Trend	Rating Action	Debt Rated
BBB	Stable	Confirmed	Long-Term Debt

RATING HISTORY	Current	2000	1999	1998	1997	1996	1995
Long-Term Debt	BBB	BBB	BBB	BBB	BBB (low)	BBB (low)	BBB (low)

UPDATE

Newfoundland and Labrador Hydro's ("the Utility") rating is a flow through of the rating of the Province of Newfoundland (see separate report dated July 24, 2001), which unconditionally guarantees the Utility's debt. The Utility's net earnings and cash flows fell significantly in 2000 largely due to the revenue cap on export sales to Hydro-Québec under the three-year recall agreement, which ended in March 2001. The reduced cash flows, combined with the sharply higher dividend requirement from the Province, resulted in a gross free cash flow deficit, which was financed with short-term debt. This resulted in a deterioration in the Utility's key ratios after five consecutive years of improvement. The favourable re-negotiation of the recall agreement with Hydro-Québec for another three years should result in a rebound in the Utility's earnings in 2001 and a further increase in 2002. Approval of the Utility's first general rate application (includes important rate increases and a gradual move to higher approved ROEs) would also provide a significant boost to the Utility's short- and long-term earnings outlook and financial profile. Despite these positive considerations, the Utility's operating cash flows are not expected to be sufficient in 2001 and 2002 to cover the proposed dividend payments to the Province and the current capital expenditure plan. Dividend payments to the Province are currently projected at \$53 million for 2001 and \$105 million in 2002. The Utility's key debt ratios will likely deteriorate in 2001 and 2002, although interest coverage ratios should rebound slightly.

The long-term financial outlook for the Utility will be greatly enhanced if its general rate application is approved. Its cash flows, however, will remain sensitive to water levels and changes in oil prices. Over the longer term, its competitiveness could 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					
	2000	1999	1998	1997	1996	1995
EBIT interest coverage (times)	1.17	1.51	1.45	1.24	1.17	1.19
% net debt in capital structure (1)	66.4%	63.1%	65.2%	68.1%	69.4%	70.1%
Cash flow/total net debt (times) (1)	0.06	0.11	0.09	0.06	0.04	0.04
Cash flow/capital expenditures (times) (1)	1.33	1.97	3.11	2.30	1.61	1.34
Net income (bef. extras.) (\$ millions)	35	68	70	43	29	33
Operating cash flow (\$ millions)	62	111	86	58	39	41
Electricity sales (millions of kWhs)	8,206	7,988	7,598	6,781	6,589	6,506
Electricity revenues (cents per kWh sold)	3.68	3.96	3.98	4.30	4.35	4.38
Variable costs (cents per net gen kWh sold)	2.35	2.17	2.04	2.02	2.10	2.08
Fixed costs (cents per net gen kWh sold)	2.25	2.33	2.46	2.32	2.46	2.45
Avg. coupon on long-term debt	8.40%	8.38%	8.73%	9.51%	10.10%	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, 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.

REGULATION

Newfoundland and Labrador Hydro is regulated by the Board of Commissioners of Public Utilities ("PUB"). 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 application includes: (1) the establishment of the rate base; (2) a rate increase of 6.7% for Newfoundland Power and a 10.4% rate increase in industrial rates effective January 1, 2002, based largely on (a) approval to re-base the price of Bunker C fuel to $20/barrel from $12.50/barrel, (the price of fuel has not been changed since 1991), and (b) an ROE of 3% (and a regulated debt/equity ratio of 85/15); (3) an increase in the Rate Stabilization Plan ("RSP") cap on Newfoundland Power to $100 million from $50 million; and (4) a variety of other matters, including the PUB's endorsement for moving to an ROE more comparable to industry norms (and a regulated debt/equity ratio of 60/40) in the longer term. In the past, regulatory approval was required only for changes in electricity rates beyond those resulting from the recovery of the RSP balance and for capital expenditure budgets.

CONSIDERATIONS

Strengths: (1) The Utility's debt is unconditionally guaranteed by the Province of Newfoundland. As a result, the rating of the Utility is a flow-through of the provincial government rating.
(2) The Utility recently filed its first full rate base application, which includes among other things, a request for a long-term approved ROE of 11% and the re-basing of the price of Bunker C fuel starting in 2002. Approval of the Utility's rate application would significantly improve the Utility's cash flow and borrowing outlook.
(3) The Utility has a two-thirds interest in Churchill Falls (Labrador) Corporation Limited, the lowest cost and possibly most efficient hydro-electric utility in North America. A long-term (until 2041) power contract with Hydro-Québec at rates well below market prices neutralizes much of the current cost advantage of this investment.
(4) The Utility's geographic isolation and unavailability of natural gas in much of the service region should minimize competitive pressures over the medium term from deregulation occurring throughout the North American industry. However, the Utility's geographic isolation also greatly limits its export potential.
(5) The Rate Stabilization Plan contributes to earnings stability over the longer term. The RSP provides for the deferral of cost variances resulting from changes in fuel prices, levels of precipitation and load. Customer rates are adjusted every 12 months to recover outstanding balances in the RSP over the following three years.

Challenges: (1) Annual cash flows are sensitive to water levels and oil prices given the Utility's generation base (about 56% hydro, 40% thermal). Although any cost variances from changes in fuel prices and water levels are deferred to the Rate Stabilization Plan and recovered over time and, therefore, do not impact earnings, they can cause significant changes in cash flows from one year to the next.
(2) The Utility has $96 million in realized foreign exchange losses. This amount will be recovered in future rates.
(3) Potential new Labrador capacity projects (which are on hold indefinitely) could be set up as independent operating companies, similar to Churchill Falls, with Newfoundland and Labrador Hydro holding an equity stake in the subsidiary. If the new entity or the projects are set up as part of Newfoundland and Labrador Hydro, the Utility's key debt ratios could be negatively impacted.
(4) A significant percentage of the Utility's electricity is thermal-based and is fuelled by Bunker C fuel, which has a high sulphur content. The Utility may have to deal with the environmental issues related to the sulphur content, which could result in increased costs.

EARNINGS

	For the years ended December 31					
($ millions)	2000	1999	1998	1997	1996	1995
Revenues	303.2	317.0	304.2	292.7	287.8	286.1
EBITDA	136.4	166.7	170.7	156.6	151.0	152.1
EBIT	100.9	130.6	138.6	126.7	122.4	124.7
Net interest expense	83.5	82.2	87.4	95.8	102.3	102.1
Net income before equity income & extraodinary items	17.4	48.4	51.2	30.9	20.1	22.6
Net income before extraordinary items	34.9	68.3	69.6	43.4	28.9	32.9
Net income	34.9	51.6	69.6	43.4	28.9	32.9

The revenue cap on export sales to Hydro-Québec was the primary reason for the sharp decline in the Utility's net income before equity earnings and extraordinary items to $17.4 million in 2000 from $48.4 million in 1999. Under the three-year recall power agreement with Hydro-Québec, which expired on March 8, 2001, any electricity sales beyond the specified revenue cap must be sold at cost. Some of the decline in export revenue was offset by higher retail sales to Newfoundland Power. Earnings were also adversely affected by higher operating and administration costs largely due to a change in accounting for employee future benefits and higher maintenance costs.

Outlook: The Utility's net income is expected to rebound in 2001 as a result of the re-negotiation of the three-year recall agreement with Hydro-Québec. The new recall agreement includes a higher revenue cap than under the previous agreement, which should result in increased net earnings from export sales over the 2001-03 period. Another factor, which will likely have a positive impact on the Utility's earnings starting in 2002 is the outcome of its first full rate base application (and first rate application since 1991-92). The Utility has applied for an increase in the cost of fuel (Bunker C fuel) included in rates from $12.50/barrel to

$20/barrel, effective January 1, 2002 (the average price of Bunker C fuel is currently over $20/barrel). If approved, this would result in a 6.7% increase in rates to Newfoundland Power and a 10.4% increase in industrial rates in 2002. It should be noted that the re-basing of fuel costs does not have a long-term impact on the Utility's earnings as any differences between the cost of fuel included in rates and actual fuel costs are recovered over time through the Rate Stabilization Plan. The Utility has also applied for an ROE of 3%, and has requested the PUB's endorsement for moving to an ROE that is more comparable with industry norms in the longer term. For example, an ROE of 11% would result in an additional 6% increase in the rate charged to Newfoundland Power. This is the first time that the Utility has applied for rates based on a rate of return on rate base.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	For years ending Dec. 31				Stress testing		
Cash flow statement (non-consolidated)	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	136.4	166.7	170.7	156.6	109.1	109.1	109.1
Net income (before extras.)	34.9	68.3	69.6	43.4	(37.5)	(51.4)	(69.8)
Depreciation	35.5	36.1	32.1	29.9	35.3	36.7	38.9
Other non-cash adjustments	(8.1)	6.8	(16.2)	(14.9)	0.0	0.0	0.0
Operating cash flow	62.3	111.2	85.5	58.4	(2.2)	(14.7)	(30.9)
Plus: dividends received	5.2	8.4	12.6	10.5	5.2	5.2	5.2
Less: common dividends	69.9	17.0	16.8	20.9	(50.0)	(50.0)	(50.0)
capital expenditures (net of contrib.)	50.7	60.8	31.5	30.0	87.0	115.0	69.0
Gross free cash flow	(53.1)	41.8	49.8	18.0	(34.0)	(74.5)	(44.7)
Less: working capital changes	2.7	3.1	(0.2)	(2.5)	0.0	0.0	0.0
Free cash flow	(55.8)	38.7	50.0	20.5	(34.0)	(74.5)	(44.7)
Less: other investments	4.2	(95.2)	(89.6)	(116.9)	0.0	0.0	0.0
Plus: net financing	60.5	(140.2)	(135.1)	(137.3)	134.0	174.5	144.7
Net change in cash	0.5	(6.3)	4.5	0.1	100.0	100.0	100.0
Total net debt (1)	1,123	1,073	1,110	1,148	1,257.3	1,431.8	1,576.5
% net debt in capital structure (1)	66.4%	63.1%	65.2%	68.1%	66.9%	73.4%	79.8%
EBIT interest coverage (times)	1.17	1.51	1.45	1.24	0.80	0.71	0.60
Cash flow/ total debt (1)	0.06	0.11	0.09	0.06	(0.00)	(0.01)	(0.02)
Stress test assumptions							
EBITDA growth					-20%	0%	0%
Interest rate					9.3%	9.3%	9.3%

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

Financial profile: A significant decline in operating cash flows combined with a sharp increase in dividends paid to the provincial government in 2000 resulted in a gross free cash flow deficit, which the Utility financed with short-term debt (promissory notes increased to $121.2 million as at December 31, 2000, from $54.4 million the previous year). Operating cash flows fell significantly in 2000 to $62.3 million from $111.2 million the previous year, largely due to: (1) the cap on export sales revenue under the recall agreement with Hydro-Québec that expired in March 2001 (any export sales beyond the cap must be sold at cost); and (2) higher fuel costs.

As a result of the reduced net earnings and the debt financing requirements, the Utility's key ratios deteriorated in 2000 after five consecutive years of improvement. Despite the deterioration, the debt-to-capital ratio remains reasonable compared to other government-owned utilities, although EBIT interest coverage and cash flow/debt remain weaker.

Outlook: Capital expenditures are projected to rise from $50.7 million in 2000, to about $87 million in 2001, and rise further in 2002 to about $115 million to finance (1) a 40 MW $135 million new hydro generating facility (Granite Canal) to meet growing demand, and (2) the ongoing five-year (1997-2002) transmission and system reliability improvement program. Despite the re-negotiation of the three-year recall agreement with Hydro-Québec, which includes a higher revenue cap on export sales, the Utility is not expected to generate sufficient operating cash flows in 2001 nor in 2002 to cover its capital expenditures and dividend payments to the Province (dividend payments estimated at $53 million in 2001 and $105 million in 2002). The Utility is expecting to issue approximately $250 million in term debt in 2001, rising to $300 million in 2002. Key debt ratios will likely remain weak in the near term, although interest coverage should improve somewhat from the higher exports sales revenues. Over the longer term, key ratios should improve if the PUB approves all the requests included in the general rate application.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Utility, or DBRS expectations concerning the future performance of the Utility.

The following scenario has been analyzed: (1) EBITDA declines 20% in 2001, and remains constant during the following two years; (2) the Utility maintains its current capital plan; and (3) the Province requires the Utility to make annual dividend payments of $50 million (in line with the current dividend requirement for 2001). Under this scenario, operating cash flow would be negative and, therefore, would be insufficient to cover the current capital plan and dividend requirements. Financial ratios would deteriorate sharply and quickly. However, DBRS expects that the Utility would receive regulatory relief and that the Province would adjust its dividend policy to stabilize the Utility's financial situation.

Operating Lines of Credit

The Utility has a Cdn$50 million operating line of credit, which currently remains unused. The Utility also has a Cdn$300 million commercial paper program. As at December 31, 2000, the Utility had Cdn$124.3 million of commercial paper outstanding. The amount of commercial paper outstanding has come down since the early part of 2001 and stood at $41.7 million at August 31, 2001.

Debt Maturity Schedule

(Includes term debt maturities and sinking fund requirements for the Utility only.)

	2001	2002	2003	2004	2005
($ millions)	162.9	112.7	12.9	8.9	9.4

Province of Newfoundland

The Province of Newfoundland's (the "Province") long-term and short-term ratings were confirmed at BBB and R-2 (high), respectively, with Stable trends, in July 2001. The confirmation reflects: (1) continued improvements in the fundamentals of the Province's economy; (2) declining tax burdens; and (3) the growing importance of the energy sector, which will likely continue to fuel growth in the future.

The recent years of strong economic growth have allowed the Province to diversify its economic base, reduce unemployment and embark on a more sustainable growth path. In 2000-01, vigorous economic activity and stronger-than-expected revenue growth led to a DBRS-adjusted surplus of $1 million, significantly better than the $122 million deficit initially anticipated. Fiscal results are forecast to weaken in 2001-02, however. Higher expenditures combined with conservative revenue forecasts are projected to lead to a DBRS-adjusted deficit of $201 million on a modified cash basis.

As a result, achieving balanced budgets remains one of the Province's main challenges. Indebtedness is also high. In 2001-02, total debt is forecast to increase approximately $150 million, to $9.6 billion. This is expected to push the Province's debt-to-GDP ratio to an estimated 67.8% which, while lower than in the mid-1990s, remains the highest among all provinces. Given more moderate increases expected in income and sustained spending pressures, especially in health care and wages, improvements on the fiscal and debt fronts are likely to be slow in the years to come. Other challenges include the relatively high, though declining, provincial tax burden and the high dependence on federal transfers, which prevents the Province from fully benefiting from new sources of revenues, as any increase in the province's revenue is largely offset by a reduction in equalization.

Newfoundland & Labrador Hydro

(Non-Consolidated)

Balance Sheet

($ millions)	As at December 31				As at December 31		
Assets:	2000	1999	1998	Liabilities & Equity:	1998	1999	1998
Cash + equivalents	0.4	4.4	6.5	Accts pay + accr'ds	57.5	63.8	71.0
Receivables	41.3	45.5	57.2	Promissory notes	125.6	58.9	88.4
Rate stabilization acct	11.5	17.0	17.0	L.t.d. due in 1 year	162.9	12.1	87.1
Fuel, supplies + prepaids	45.0	44.9	32.7	Current liabilities	346.0	134.8	246.5
Current assets	98.2	111.8	113.4	Long-term debt	870.2	1,030.8	1,047.3
Fixed assets	1,256.8	1,243.2	1,237.1	Fx losses	9.0	8.0	7.0
Investments	293.2	290.0	285.8	Employee future benel	22.8	2.0	0.0
Rate stabilization acct	24.1	17.5	31.7	Shareholders' equity	568.6	626.2	591.6
Sinking funds	35.4	28.8	113.3				
Def'd charges + long-term receivables	108.9	110.5	111.1				
Total	1,816.6	1,801.8	1,892.4	Total	1,816.6	1,801.8	1,892.4

Ratio Analysis (1)	For years ended December 31							
Liquidity Ratios	2000	1999	1998	1997	1996	1995	1994	1993
Current ratio	0.28	0.83	0.46	0.24	0.31	0.20	0.39	0.44
Accumulated depreciation/gross fixed assets	23.2%	22.1%	21.1%	19.4%	17.9%	16.5%	15.1%	13.7%
Cash flow/total net debt (2)	0.06	0.11	0.09	0.06	0.04	0.04	0.05	0.05
Cash flow/capital expenditures	1.33	1.97	3.11	2.30	1.61	1.34	2.38	2.21
Cash flow-dividends/capital expenditures	(0.05)	1.69	2.58	1.60	1.15	0.81	2.38	2.21
% net debt in capital structure (2)	66.4%	63.1%	65.2%	68.1%	69.4%	70.1%	70.3%	69.6%
Average coupon on long-term debt	8.40%	8.38%	8.73%	9.51%	10.10%	10.10%	10.80%	10.60%
Common equity in capital structure	33.6%	36.9%	34.8%	31.9%	30.6%	29.9%	29.7%	30.4%
Common dividend payout (before extras.)	200.3%	24.9%	24.1%	48.2%	44.6%	59.3%	0.0%	0.0%
Coverage Ratios (3)								
EBIT interest coverage	1.17	1.51	1.45	1.24	1.17	1.19	1.11	1.14
EBITDA interest coverage	1.54	1.89	1.71	1.45	1.38	1.39	1.30	1.32
Fixed-charges coverage	1.17	1.51	1.45	1.24	1.17	1.19	1.11	1.14
Earnings Quality / Operating Efficiency								
Power purchases/revenues	6.7%	6.0%	4.4%	1.9%	1.8%	1.7%	1.9%	1.5%
Fuel costs/revenues	14.0%	11.1%	8.8%	15.0%	14.5%	14.1%	14.0%	14.9%
Operating margin	33.3%	41.2%	45.6%	43.3%	42.5%	43.6%	42.5%	43.6%
Net margin (before extras.)	11.5%	21.5%	22.9%	14.8%	10.0%	11.5%	7.6%	8.7%
Return on avg equity (before extras.)	5.8%	11.2%	12.3%	8.2%	5.7%	6.7%	4.5%	5.4%
Profit returned to government (bef extras.) (4)	176.8%	35.3%	34.8%	58.7%	59.7%	69.1%	33.3%	29.5%
GWh sold/employee	8.1	7.7	7.3	6.7	6.5	6.1	5.5	5.3
Self Generation - Cost Structure (5)	(cents per net generated kWh sold) (Tables may not add due to rounding)							
OM&A	1.62	1.54	1.54	1.28	1.37	1.37	1.44	1.38
Fuel	0.74	0.63	0.51	0.74	0.72	0.71	0.70	0.74
Variable costs	2.35	2.17	2.04	2.02	2.10	2.08	2.14	2.12
Gov't levies	0.19	0.20	0.21	0.19	0.19	0.18	0.19	0.18
Net interest expense	1.48	1.48	1.60	1.58	1.71	1.73	1.87	1.83
Total cash costs	4.01	3.85	3.86	3.79	4.00	3.99	4.20	4.13
Non-cash financial charges	(0.03)	0.01	0.04	0.05	0.07	0.06	0.05	0.10
Depreciation	0.62	0.65	0.60	0.51	0.50	0.48	0.47	0.42
Total costs	4.60	4.50	4.50	4.34	4.56	4.53	4.72	4.65
Purchased power (cents per gross kWh purchased)	0.80	0.74	0.57	0.61	0.60	0.60	0.62	0.59

(1) Debt related ratios not directly comparable to periods before 1996 due to a change in accounting policies.

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

(3) Before capitalized interest, AFUDC and debt amortizations.

(4) Includes all taxes, guarantee fees and dividends.

(5) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

Operating Statistics		For years ended December 31					
Electricity Sold - Breakdown		2000	1999	1998	1997	1996	1995
Utilities (mainly Nfld L+P)		4,263	4,084	4,157	4,306	4,187	4,214
Rural		842	830	811	815	765	751
Industrial		1,607	1,343	1,286	1,660	1,637	1,541
Exports		1,494	1,731	1,344	0	0	0
Total (GWh sold)		8,206	7,988	7,598	6,781	6,589	6,506
Energy sales growth		2.7%	5.1%	12.0%	2.9%	1.3%	2.2%
Generation							
Hydro	56%	899	899	899	899	899	899
Thermal	40%	645	645	645	645	645	645
Diesel	4%	58	58	58	58	58	57
Installed capacity (MW)		1,602	1,602	1,602	1,602	1,602	1,601
Energy Generated - hydro		5,016	4,801	4,260	4,628	4,574	4,393
- thermal		966	914	1,255	1,528	1,409	1,533
- diesel		43	41	41	41	64	74
Gross energy generated - GWh	69%	6,025	5,756	5,556	6,197	6,047	6,000
Plus: purchases	31%	2,545	2,538	2,382	932	878	838
Energy generated + purchased		8,570	8,294	7,938	7,129	6,925	6,838
Less: transmission losses + internal use		364	306	340	348	336	332
Total - GWh sold		8,206	7,988	7,598	6,781	6,589	6,506
Energy lost + used/energy gen + purch		4.2%	3.7%	4.3%	4.9%	4.9%	4.9%
Maximum primary peak demand		1,240	1,265	1,295	1,229	1,318	1,250
Peak demand/available capacity		77.4%	79.0%	80.8%	76.7%	82.3%	78.1%
Unit Revenues & Costs		(cents per kWh sold) (Tables may not add due to rounding)					
Revenues:							
Utilities		4.49	4.50	4.49	4.48	4.50	4.50
Rural		5.88	5.55	5.40	5.51	5.83	5.97
Industrial		2.96	3.56	3.27	3.23	3.27	3.27
Exports		0.89	2.22	2.22	-	-	-
Average electricity revenues		3.68	3.96	3.98	4.30	4.35	4.38
Ancillary revenues		0.02	0.01	0.02	0.02	0.02	0.02
Average revenues		3.69	3.97	4.00	4.32	4.37	4.40
Costs:							
Operating + administration		1.14	1.07	1.08	1.11	1.20	1.20
Power purchases		0.25	0.24	0.18	0.08	0.08	0.08
Fuel		0.52	0.44	0.35	0.65	0.63	0.62
Variable costs		1.90	1.74	1.61	1.84	1.91	1.90
Government levies		0.13	0.14	0.15	0.16	0.16	0.16
Net interest expense		1.04	1.03	1.12	1.37	1.49	1.52
Cash costs		3.07	2.91	2.88	3.38	3.57	3.58
Cash margin		0.63	1.06	1.13	0.94	0.80	0.82
Non-cash financial charges		(0.02)	0.00	0.03	0.04	0.06	0.05
Depreciation		0.43	0.45	0.42	0.44	0.43	0.42
Pre-tax margin		0.21	0.61	0.67	0.46	0.31	0.35
Variable costs		1.90	1.74	1.61	1.84	1.91	1.90
Fixed costs (deprec, int + levies)		1.58	1.62	1.72	2.02	2.15	2.15
Total costs		3.48	3.36	3.33	3.86	4.06	4.05

Nova Scotia Power Inc.

Current Report: May 25, 2001
Previous Report: February 28, 2000

RATING

Rating	*Trend*	*Rating Action*	*Debt Rated*
A (low)	Stable	Confirmed	Unsecured Debentures & MTNs
A (low)	Stable	Confirmed	Gov't guaranteed debt (issued prior to June 1993)
Pfd-2 (low)	Stable	Confirmed	Preferred shares - cumulative, redeemable

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RATING HISTORY (as at Dec. 31)	*Current*	*2000*	*1999*	*1998*	*1997*	*1996*
Long-Term Debt	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	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 long-term and preferred share ratings of Nova Scotia Power Inc. ("Nova Scotia Power" or "the Utility") at A (low) and Pfd-2 (low), respectively, based on the following considerations. (1) The Utility is generating substantial cash flows well in excess of internal needs. With a mature market and no need for material capital investments, the Utility is expected to continue to generate more than sufficient cash flows, even in light of growing earnings pressures. (2) A regulated capital structure, which ensures that the debt-to-equity ratio remains stable, reflecting a 35% deemed equity. The regulatory environment is relatively favourable compared to other Canadian jurisdictions and the Utility's approved ROE of 10.75% has not changed since 1996 in spite of a material decline in interest rates over the period. However, the Utility will have to contend with growing earnings pressures from a number of sources. The development of a $1.1-billion gas distribution infrastructure across the province may negatively affect load growth over the longer term as new homes are fitted for gas. The Utility has been proactive in preparing for growing competitive pressures, introducing "time of use" rates for large users. This should help minimize industrial load loss and allow the Utility to better manage peak load requirements, leading to a more efficient use of available capacity. Escalating fuel costs and a growing tax burden at both the provincial and federal levels are other factors that will pressure earnings over the near term. Under cost of service regulation, both costs are normally passed through to customers, but increasing rates would widen the competitive gap relative to other fuel alternatives just as natural gas becomes more readily available. In addition, environmental risks related to a potential tightening of emission standards in the future is a longer term challenge. The Utility will have to focus on containing costs to retain its existing load, but could potentially access export markets in the U.S. northeast should domestic demand fall below available capacity.

RATING CONSIDERATIONS

Strengths:

- Regulation ensures balance sheet remains stable, contributes to relative earnings/cash flow stability
- Material surplus cash flows for foreseeable future
- Geographic isolation and limited interconnections are effective barriers against external competitors

Challenges:

- Competitive pressures: gas distribution network under development, electricity industry deregulation
- Fully taxable in 2004; cost will wide competitive gap relative to other fuel alternatives
- High-cost generator/low population density of franchise
- Future environmental risks: coal-based plants

FINANCIAL INFORMATION

For years ended December 31

	2000	1999	1998	1997	1996	1995
Fixed-charges coverage (times)	1.98	1.93	1.78	1.82	1.62	1.49
Debt in capital structure (incl. debt equiv.)	65.4%	65.8%	67.2%	67.8%	69.0%	68.7%
Cash flow/total debt (times) (incl. debt equiv.)	0.14	0.13	0.12	0.12	0.11	0.08
Cash flow/capital expenditures (times)	2.03	2.07	1.70	2.23	2.28	1.73
EBIT ($ millions)	254.5	254.4	238.7	252.6	259.7	259.0
Net income (after pfd. div's.) ($ millions)	103.7	103.2	85.5	92.7	90.0	94.8
Operating cash flow ($ millions)	246.1	236.3	223.5	223.9	202.0	152.2
Electricity sales (GWh)	10,656	10,365	9,772	9,516	9,146	9,035

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. (formerly NS Power Holdings Inc.), which is a widely held company listed on the Toronto Stock Exchange.

REGULATION

Nova Scotia Power Inc. is regulated by the Nova Scotia Utility and Review Board (“UARB”) and operates under a cost of service/rate of return methodology. Implementation of a performance-based methodology is presently under consideration (by the Nova Scotia Power) and may involve a sharing of "excess earnings" mechanism. The regulatory environment is favourable compared to other jurisdictions and there has been no change in the applicable approved ROE (10.75%) since 1996. The ROE is higher than what other integrated regulated utilities are currently allowed for 2001 (in the 9.75%-10% range).

RATING CONSIDERATIONS

Strengths: (1) Regulation ensures that balance sheet strength remains stable, reflecting a 35% deemed equity. The cost of service/rate of return methodology also contributes to relative earnings and cash flow stability.
(2) With a mature franchise and no need for significant additions to the existing infrastructure, internally generated cash flows are expected to be more than sufficient to meet internal needs over the foreseeable future. As the equity component of the Company's capital structure has now reached the allowed 35% maximum, all residual earnings will be paid out in dividends to parent Emera Inc.
(3) In spite of electricity rates that are among the highest in Canada and which could potentially attract competition, the Utility’s limited interconnection capacity and isolated geographic position provide an effective barrier against new market entrants. Neighbouring utilities in the U.S. Northeast have significantly higher electricity rates and are therefore 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 they could generate higher revenues.
(4) The federal government recently announced the shutdown of the coal mines (Cape Breton Development Corporation, "Devco") that historical supplied Nova Scotia Power Inc. Devco will supply about 30% of the Company's required coal supplies during 2001, but Nova Scotia Power will likely source all of its coal supply requirements from other sources at some point in the near future. Using imported coal would materially reduce emissions, as the Devco mine produces high sulfur coal.
(5) The competitive threat posed by the pending availability of natural gas should be partially offset by the following benefits: (a) lower overall fuel costs and improved operating efficiencies following the conversion of the 450-MW, oil-fuelled Tufts Cove plant to dual firing capability; (b) a reduction in future environmental risks due to lower emissions; and (c) the potential for export sales to power short U.S. northeast markets should domestic demand fall below available capacity.
(6) Debt existing prior to the 1992 privatization has been defeased (as of March 1996).

Challenges: (1) Given its environmental and cost advantage, natural gas represents a material competitive threat in terms of load loss over the mid to longer term. The impact on earnings is, however, expected to be minimal over the near to mid term due to the following factors. (a) It will take time to build a gas distribution infrastructure in the province. Laterals currently deliver gas to the Utility's Tufts Cove plant and to processing facilities in Point Tupper. Additional laterals to allow for gas distribution are scheduled for completion between 2004 and 2007. (b) Residential Load Loss: Only 25% of the homes in the province are heated by electricity (60% by oil and 15% by wood burning systems). The relatively high capital cost to convert electricity-based home heating systems to gas (in the $5,000 range, with a seven to ten year payback period) and the present high cost of gas will discourage residential conversions over the near to mid term. Water heaters in the province are largely electricity-based. Conversion to gas, as they come due for replacement, would be more economical. Home heating and water heater sales each accounted for 20% of the Utility's residential electricity load in 2000. The most likely impact on residential revenues will be reflected in slower growth in the future as gas-based residential systems are installed in new homes. (c) Industrial and Commercial Load Loss: "Time of use" strategies should help to minimize load loss over the near to mid term. Implementation of the new rate structure was supported by a majority of these two customer segments who have indicated that the rate reductions would be sufficient to deter conversion. Load loss could occur where a customer's electricity needs are large enough to support a co-generation plant, but most do not presently have the required steam/electricity profiles. The maximum industrial load loss at risk is limited to about 7.5% of current electricity sales. (d) Earnings pressures from gas will be partially offset by several benefits. (see Strength 4). Rather than displacing significant amounts of current generated electricity, gas will likely be used to meet future power needs through new gas-fired plants, heating systems and co-generation facilities where appropriate.
(2) Earnings are sensitive to weather as space heating accounts for about $6 million of gross revenues (or roughly 700 GWh of electricity sales) during a normal temperature winter. The Company uses weather temperature contracts to limit this sensitivity during the first and fourth quarters when electricity sales for home heating use are at their peak. Excluding the impact of these financial instruments, a 5% change in degree days would impact net earnings by about $2.3 million.
(3) Nova Scotia Power Inc. will become fully taxable in 2003, when most of the existing tax credits expire. The additional cost burden, if fully passed through with rate increases, would widen the competitive gap between electricity and alternative sources of energy.
(4) Nova Scotia Power is one of the highest-cost generators in Canada, even when compared against other thermal-based operators. In addition, relatively high electricity rates make Nova Scotia an attractive market to potential competitors. The other primary factor that contributes to

the Utility's high cost structure, a lack of economies of scale due to a low population density in the province, will be difficult to overcome.

(5) The Utility's generating capacity (and at least 70% of energy available for sale) is 58% coal-based. As these plants burn high sulfur content coal, the Utility must manage future environmental risks associated with changes in emission standards. A tightening of emission standards might require the installation of expensive scrubbers on existing coal-based facilities.

(6) Competitive pressures are expected to increase over the longer term as the North American electricity industry continues to deregulate. However, the provincial government has no plans to introduce deregulation during its current political mandate. Implementation would probably be phased-in with wholesale (re-sellers) competition allowed before the market was opened for retail competition.

(7) The Canada Customs and Revenue Agency has disallowed certain capital cost allowances Nova Scotia Power claimed in amended tax returns for the 1999 and 2000. The total liability under this reassessment amounts to $118 million. The Utility is contesting the disallowance, but if it is unsuccessful, Nova Scotia Power can apply to the UARB to recover these costs in future rates. The amount, if any, that would be passed through to customers would likely be phased in over a period of time.

EARNINGS PROFILE

Income Statements ($ millions)	Yr / Yr	For years ended December 31					
Revenues	Chg	2000	1999	1998	1997	1996	1995
Residential	3.2%	351.6	340.6	329.7	339.0	333.3	313.0
Commercial	2.8%	227.4	221.3	212.9	214.6	218.7	219.7
Industrial	1.9%	197.3	193.7	173.1	147.9	144.8	146.7
Other	6.9%	37.0	34.6	35.1	39.9	33.8	32.3
Gross electricity revenues	2.9%	813.3	790.2	750.8	741.4	730.6	711.7
Other	-32.2%	5.9	8.7	5.3	7.3	10.6	8.9
Total revenues	2.5%	819.2	798.9	756.1	748.7	741.2	720.6
Expenses							
Power purchases	-15.2%	21.2	25.0	16.3	21.5	17.2	16.3
Fuel	4.2%	252.7	242.5	241.0	224.9	221.5	228.5
Operating + maintenance	9.0%	157.0	144.0	140.1	138.6	157.7	147.7
Grants in lieu of taxes	12.7%	17.7	15.7	12.2	10.5	5.2	5.2
EBITDA	-0.3%	370.6	371.7	346.5	353.2	339.6	322.9
Depreciation	3.1%	97.1	94.2	91.1	87.8	85.0	86.5
EBITA	-1.4%	273.5	277.5	255.4	265.4	254.6	236.4
Amortizations	-17.7%	19.0	23.1	16.7	12.8	(5.1)	(22.6)
EBIT	0.0%	254.5	254.4	238.7	252.6	259.7	259.0
Interest expense	-1.5%	110.8	112.5	118.0	126.4	150.6	175.7
Non-cash financing charges	0.6%	16.1	16.0	17.6	18.6	18.4	15.4
Other (income)/expense	-77.8%	(0.4)	(1.8)	(7.1)	(8.8)	(24.3)	(48.9)
Net interest expense	-0.2%	126.5	126.7	128.5	136.2	144.7	142.2
Pre-tax income	0.2%	128.0	127.7	110.2	116.4	115.0	116.8
Income taxes	9.1%	14.4	13.2	13.5	14.2	11.4	5.2
Net income before extras.	-0.8%	113.6	114.5	96.7	102.2	103.6	111.6
Preferred div's. net of tax recovery	-12.4%	9.9	11.3	11.2	9.5	13.6	16.8
Net income available to common shlders	0.5%	103.7	103.2	85.5	92.7	90.0	94.8
Electricity sold (GWh)	2.8%	10,656	10,365	9,772	9,516	9,146	9,035

In spite of a 2.8% increase in GWh sold, EBIT were flat and earnings available to common shareholders were up only marginally in 2000 compared to the previous year. EBIT and net earnings were affected by following factors.

- A return to more normal winter temperatures (temperatures were 7.9% warmer than normal in 2000 compared to 15.1% warmer than normal in 1999) accounted for much the increase in electricity sold. The adverse impact on earnings of abnormal winter temperatures is moderated by the use of financial hedges.
- EBIT should have benefited from the cessation of the amortization (1994 - 1999) of certain costs related to the commissioning of Point Aconi plant in 1994. However, the Utility has decided to permanently shutdown the Glace Bay plant that was decommissioned in 1995. Costs related to the unrecovered capital investment ($35 million as of

December 1999) and site restoration expenses ($11.8 million) will be recovered over the 2000-2002 period.
- Savings from a sharp increase in coal-based generation, which replaced higher cost external power purchases, were partially offset by higher oil and natural gas fuel costs.
- Higher maintenance expenditures related to the Tufts Cove conversion to a dual firing facility. This investment should help the Company to take advantage of fuel cost differentials in the future.
- The refinancing of 6% Series A preferred shares with Series C 4.9% preferred shares during 2000 reduced the preferred dividend obligation payable.

Outlook: Earnings will be under pressure from a number of factors and the Utility will need to contain costs and/or increase rates to maintain earnings at current levels. Two factors in particular, rising fuel costs and a growing tax burden, will adversely affect earnings over the near term.
Both of these costs are normally passed through to customers, but the Utility must obtain regulatory approval to implement the necessary rate increases. In addition, the Utility must consider the impact that rate increases might have in terms of its competitive position. The increase in electricity rates would widen the competitive gap between electricity and other sources of energy, however, amortization expenses should fall substantially in 2003, when the Utility will have completed the recovery related to the permanent shutdown of Glace Bay.

- Both natural gas and coal prices have been rising and reduced EBIT and net earnings in the first quarter of 2001 relative to the previous year.
- Provincial taxes are expected to increase by $2 million annually in each of the next two years. In addition, federal tax obligations will increase materially by 2004 after tax loss carry forwards expire in 2003. Normally net earnings are not affected by taxes as the expense flows through to customers, but the increase in EBIT typically results in an improvement in coverage ratios.
- A slowing economy will moderate electricity load growth over the near term. Over the longer term, load growth should benefit from an improvement in the province's economic outlook as a result of growing exploration and development of offshore oil and gas fields as well as the $1.1 billion development of the gas distribution infrastructure. Long-term load growth may also be moderated by growing competitive pressures as the new gas distribution infrastructure is developed and extended across the province over the next few years. The county of Halifax, which accounts for over one-third of the province's population, is scheduled to be connected by 2004, and other population centers by 2007. However, relatively high gas prices and the high capital cost of conversions makes residential load loss unlikely at least over the next few years. Residential load growth is expected to slow in the future as new homes are fitted for gas heating rather than electricity. The Utility has taken a proactive approach by offering lower "time of use" rates to higher volume customers who purchase power during off-peak periods that should minimize industrial load loss. This should also allow for better management of peak load requirements and more efficient use of available capacity. Note that the Utility could potentially increase exports to the power short U.S. northeast should domestic load fall below available generating capacity.
- A 25 basis point change in the approved ROE would impact net earnings by about $2.2 million in 2002. Nova Scotia Power has not requested any increase in customer rates since 1997, so there has been no change in the Utility's approved ROE since 1996 in spite of a material decline in interest rates over the period. Approved ROEs for other integrated regulated utilities are currently in the 9.75%-10% range.

FINANCIAL PROFILE

	For years ended December 31					
($ millions)	2000	1999	1998	1997	1996	1995
Net income available to common shlders	103.7	103.2	85.5	92.7	90.0	94.8
Depreciation + amortizations	159.8	148.0	138.0	131.2	112.0	57.4
Other non-cash adjustments	(17.4)	(14.9)	0.0	0.0	0.0	0.0
Operating Cash Flow	246.1	236.3	223.5	223.9	202.0	152.2
LESS: capital expenditures (net of contrib.)	121.4	114.1	131.2	100.3	88.5	88.0
Cash flow before working capital	124.7	122.2	92.3	123.6	113.5	64.2
LESS: working capital changes	11.5	(15.6)	29.6	(71.3)	21.6	(28.1)
Free cash flow before dividends	113.2	137.8	62.7	194.9	91.9	92.3
LESS: common dividends	93.2	72.2	71.1	69.9	68.7	66.7
Free cash flow after dividends	20.0	65.6	(8.4)	125.0	23.2	25.6
PLUS: net debt financing	(37.8)	(96.9)	8.4	(130.7)	(28.6)	(28.1)
PLUS: net pfd. financing	17.8	31.3	0.0	0.0	0.0	0.0
PLUS: net common equity financing	0.0	0.0	0.0	6.3	5.4	2.5
Net change in cash flows	0.0	0.0	0.0	0.6	(0.0)	0.0
Cash flow/capital expenditures (times)	2.03	2.07	1.70	2.23	2.28	1.73
Cash flow/total debt (times)	0.14	0.13	0.12	0.12	0.11	0.08
% Debt in the capital structure	65.4%	65.8%	67.2%	67.8%	69.0%	68.7%
Fixed-charges coverage (times)	1.98	1.93	1.78	1.82	1.62	1.49

Capital expenditures during 2000 included a material investment to convert Tufts Cove to a dual firing facility. Internally generated cash flows were more than sufficient, and to maintain the common equity component of the capital structure at the 35% regulated limit, the Utility substantially increased dividend payments to its parent Emera Inc. to $93 million from $72 million the previous year. Key debt ratios were stable relative to the previous year.

Outlook: With a mature market and no need for any material investments in utility assets, capital expenditures are expected to remain below the $125-million range for the foreseeable future. Even with a potential decline in earnings (see Earnings Outlook), internally generated cash flows should be more than sufficient to meet internal needs given that the cash flow/capital expenditure ratio is currently at 2 times.

With a regulated capital structure, financial leverage should remain stable and the debt-to-equity ratio will continue to reflect a 35% deemed equity.

Interest coverage ratios may come under some pressure over the near term due to the earnings pressures cited above, but could potentially improve materially in 2003 when the Company becomes fully taxable. Note that all other things equal, income taxes will increase revenues and EBIT, but leave net earnings and cash flows unaffected.

OPERATING LINES OF CREDIT

A $150-million demand line of credit, in addition to a fully committed bank line that supports a $350-million commercial paper program.

DEBT MATURITY / PREFERRED SHARE REDEMPTION SCHEDULES

(As at December 2000)

Unsecured Debentures ($ millions)

Years to Maturity	Principal	Average Coupon
1 year	120.5	7.28%
2 years	120.0	7.88%
3 years	150.0	7.70%
4 years	65.0	7.30%
5 years	100.0	8.38%
Subtotal	555.5	7.72%
Over 6 years	720.0	7.48%
Total	1,275.5	7.59%

Preferred Shares ($ millions)

Redemption	Series C	Series D
April 2009	$125.0*	-
October 2015	-	$135.0

*Includes conversion of Series B + warrants during Q1 2001.

Long-term debt maturities over the next five years are relatively small and well staggered. All preferred shares are redeemable at the Utility's option. The Series C and D preferred shares are treated as debt equivalents (both are convertible at the holder's option into common shares of parent Emera Inc.). Note that for regulatory purposes, the preferred shares are debt instruments.

Nova Scotia Power Inc.

Balance Sheet
($ millions)

	As at December 31				As at December 31		
Assets	2000	1999	1998	**Liabilities & equity**	2000	1999	1998
Cash	0.1	0.1	0.1	Short-term debt	202.1	239.1	348.7
Receivables	85.5	54.6	78.9	A/P + accr'd liab	158.6	128.1	118.7
Inventories	83.1	75.3	27.3	LTD due in 1 year	120.5	8.1	163.5
Prepaids + other	3.8	3.5	29.5	Current liabilities	481.2	375.3	630.9
Current assets	172.5	133.5	135.8	Def'd credits	0.4	2.2	0.0
Long-term receivable	13.7	5.6	0.0	Long-term debt	1,155.0	1,260.5	1,083.5
Net fixed assets	2,367.5	2,357.4	2,333.7	Preferred shares	249.1	231.3	200.0
Deferred expenses	285.0	315.3	357.4	Shareholders' equity	953.0	942.5	912.5
Total	2,838.7	2,811.8	2,826.9	Total	2,838.7	2,811.8	2,826.9

Ratio Analysis	For years ended December 31							
Liquidity Ratios (1)	2000	1999	1998	1997	1996	1995	1994	1993
Current ratio	0.44	0.46	0.30	0.33	0.41	0.41	0.33	0.58
Accumulated depreciation/gross fixed assets	34.5%	33.1%	31.9%	30.8%	29.8%	28.5%	27.0%	25.4%
Cash flow/total debt (2)	0.14	0.13	0.12	0.12	0.11	0.08	0.09	0.09
Cash flow/capital expenditures (3)	2.03	2.07	1.70	2.23	2.28	1.73	1.73	1.31
Cash flow-dividends/capital expenditures (3)	1.26	1.44	1.16	1.54	1.51	0.97	1.04	0.81
% Debt in capital structure (2)	65.4%	65.8%	67.2%	67.8%	69.0%	68.7%	69.2%	69.5%
Average coupon on long-term debt	7.59%	7.58%	7.99%	8.03%	8.15%	8.74%	9.59%	9.94%
Deemed common equity	35%	35%	35%	35%	35%	35%	35%	35%
Common dividend payout (bef. extras.)	89.9%	70.0%	83.2%	75.4%	76.3%	70.4%	68.9%	56.4%
Coverage Ratios (4)								
EBIT interest coverage	2.30	2.28	2.08	2.07	1.89	1.75	1.63	1.37
EBITDA interest coverage	3.35	3.32	3.00	2.86	2.42	2.12	1.95	1.69
Fixed-charges coverage	1.98	1.93	1.78	1.82	1.62	1.49	1.39	1.32
Earnings Quality / Operating Efficiency								
Fuel costs/revenues	30.8%	30.4%	31.9%	30.0%	29.9%	31.7%	33.5%	33.9%
EBIT margin	31.1%	31.8%	31.6%	33.7%	35.0%	35.9%	35.6%	33.3%
Net margin (bef. extras. after pfd.)	12.7%	12.9%	11.3%	12.4%	12.1%	13.2%	13.1%	16.0%
Return on avg equity (bef extras.)	10.9%	11.1%	9.5%	10.6%	10.6%	11.5%	11.9%	14.9%
Approved ROE - mid point	10.75%	10.75%	10.75%	10.75%	10.75%	11.75%	11.75%	11.75%
Customers/employee	248	276	266	246	223	217	190	186
Growth in customer base	0.9%	0.8%	1.5%	0.8%	1.1%	1.1%	0.9%	1.9%
GWh sold/employee	6.0	6.5	6.0	5.5	4.8	4.7	4.1	4.0
Degree day deficiency (% normal)	92.2%	84.9%	90.1%	100.5%	97.7%	97.6%	97.7%	102.8%
Rate base ($millions)	2,411	2,374	2,350	2,322	2,304	2,319	2,324	1,877
Growth in rate base	1.5%	1.0%	1.2%	0.8%	-0.6%	-0.2%	23.8%	2.1%
Self Generation (Cost Structure) (5)	(Cents per net generated kWh sold) (Tables may not add due to rounding)							
OM & A	1.51	1.44	1.47	1.51	1.77	1.72	1.73	1.73
Fuel	2.43	2.43	2.52	2.44	2.49	2.67	2.73	2.76
Variable costs	3.95	3.87	3.99	3.95	4.26	4.39	4.46	4.49
Gov't levies	0.17	0.16	0.13	0.11	0.06	0.06	0.06	0.06
Net interest expense	1.06	1.11	1.16	1.28	1.42	1.48	1.61	1.81
Total cash costs	5.18	5.14	5.28	5.34	5.73	5.93	6.13	6.36
Non-cash financial charges	0.16	0.16	0.18	0.20	0.21	0.18	0.02	(0.49)
depreciation + amortizations	1.12	1.18	1.13	1.09	0.90	0.75	0.66	0.81
Total costs (excl income taxes)	6.45	6.47	6.59	6.64	6.84	6.86	6.81	6.68
Income taxes (cents per net gen kWh sold)	0.14	0.13	0.14	0.15	0.13	0.06	0.01	0.06
Purchased power (cents per gross kWh purch.)	7.18	6.08	6.74	6.32	6.76	3.26	3.24	3.02
Preferred dividends (cents per net gen kWh sold)	0.10	0.11	0.12	0.10	0.15	0.20	0.19	0.04

(1) Securitization sales added back to receivables and short-term debt for ratio calculations.
(2) Preferred shares treated as debt equivalents.
(3) Capital expenditures net of customer contributions.
(4) EBIT includes interest income. Interest expense before capitalized interest, AFUDC and debt amortizations. Preferred dividends net of tax recovery.
(5) Internally generated energy less energy used + lost, excludes power purchases. Transmissions losses apportioned relative to total energy supplied.

Nova Scotia Power Inc.

Operating Statistics		For years ended December 31							
Electricty Sold		2000	1999	1998	1997	1996	1995	1994	1993
Residential		3,632.1	3,494.6	3,377.9	3,498.9	3,471.9	3,380.3	3,445.3	3,400.3
Commercial		2,661.9	2,582.8	2,485.9	2,506.7	2,505.7	2,483.9	2,455.4	2,440.1
Industrial		3,917.2	3,834.8	3,423.7	2,842.6	2,754.1	2,820.9	2,715.0	2,706.3
Other (including exports)		445.0	453.2	484.4	667.7	413.9	349.7	350.2	347.4
Total (GWh sold)		10,656.2	10,365.4	9,771.9	9,515.9	9,145.6	9,034.8	8,965.9	8,894.1
Energy sales growth		2.8%	6.1%	2.7%	4.0%	1.2%	0.8%	0.8%	1.0%
Generation									
Coal	58%	1,272	1,272	1,272	1,272	1,272	1,388	1,388	1,218
Hydro	17%	381	381	381	381	381	381	381	381
Dual fuel	11%	250	0	0	0	0	0	0	0
Oil	5%	100	350	350	350	350	350	350	350
Gas turbine	8%	180	180	180	180	180	180	180	180
Installed capacity (megawatts)		2,183	2,183	2,183	2,183	2,183	2,299	2,299	2,129
Long-term IPP contracts (megawatts)		25	25	25	25	25	3		
Energy generated - GWh									
Coal		8,863.7	7,816.0	7,015.0	8,246.5	7,850.3	7,053.1	7,159.7	6,345.6
Natural gas		43.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil		1,347.8	1,870.9	2,358.3	781.4	608.7	1,239.4	1,205.7	2,117.2
Hydro		881.2	980.7	890.9	934.9	1,111.6	883.2	1,012.0	877.6
Gross energy generated	97%	11,136.5	10,667.6	10,264.2	9,962.8	9,570.6	9,175.7	9,377.4	9,340.4
PLUS: purchases	3%	295.2	411.3	242.0	340.2	254.6	499.5	216.2	218.9
Energy generated + purchased		11,431.7	11,078.9	10,506.2	10,303.0	9,825.2	9,675.2	9,593.6	9,559.3
LESS: transmission losses/internal use		775.5	713.5	734.3	787.1	679.6	640.4	627.7	665.2
Total (GWh sold)		10,656.2	10,365.4	9,771.9	9,515.9	9,145.6	9,034.8	8,965.9	8,894.1
Energy lost + used/Energy gen. + purch.		6.8%	6.4%	7.0%	7.6%	6.9%	6.6%	6.5%	7.0%
Export Interconnections (Megawatts)									
New Brunswick Power		500	500	500	500	500	500	500	500
As % of installed capacity		22.9%	22.9%	22.9%	22.9%	22.9%	21.7%	21.7%	23.5%

Ontario Power Generation Inc.

Current Report: October 2, 2001
Previous Report: June 7, 2000
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RATING

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

RATING HISTORY

	Current	2000	1999	1998	1997
Unsecured Debt	"A"	"A"	NR	NR	NR

RATING UPDATE

DBRS is confirming the rating of "A", with a Stable trend, for the long-term debt of Ontario Power Generation Inc. ("OPG" or "the Company"), as the Company continues to prepare for an open market for electricity at the wholesale and retail level in Ontario. Under the Market Power Mitigation Framework (MPMF), put in place by the Ontario government, OPG realizes approximately 3.8 cents per kWh on roughly two-thirds of its Ontario sales. The MPMF prevents OPG from fully recovering rising fuel costs, and contributes to the present earnings squeeze. In addition, the return to operations of the 2,100 MW Pickering A station is also delayed, although the first unit to return to service should begin operations starting in 2002. A long-term lease of the Bruce nuclear stations was completed in May 2001, and the Company is in the process of divesting the Lakeview, Lennox, Thunder Bay and Atikokan fossil generating units (3,805 MW) and four hydroelectric stations on the Mississagi river (488 MW), which ultimately will reduce OPG's generation capacity to approximately 20,400 MW. This is less than peaking demand in Ontario, but higher than "base" load demand near 16,000 MW in the province. The Company is successfully implementing a culture change, from a "monopoly" government-owned entity to an enterprise, which is flexible and able to compete in the open market. The Company has considerable strength in the following factors: (1) the rich franchise area served; (2) the competitive cost structure with extremely low variable costs; and (3) an extremely strong balance sheet, with debt levels near 40%, giving it some of the strongest financial ratios amongst North American energy companies. Challenges, which remain, can be overcome. The fuel cost squeeze problem should be alleviated once open market conditions are introduced. The return to service of the four Pickering A units will likely contribute $300 million in cash flows annually. Environmental concerns are industry wide and not specific to OPG, and the government ownership situation is evolving. Thus, the Company is making progress across many fronts, as it goes through a substantial transformation.

RATING CONSIDERATIONS

Strengths:

- Attractive business franchise area
- Competitive with U.S. electricity rates
- Above-average balance sheet
- Leading market position in Ontario
- Nuclear liability position capped

Challenges:

- Fuel cost rise squeezes earnings
- Delays at Pickering A
- Growing competition domestically
- Environmental concerns with coal-related emissions
- Government ownership

FINANCIAL INFORMATION

	Ontario Power Generation	Part of Ontario Hydro			
	12 months	For years ended December 31 (1)			
	June 2001	2000	1999	1998	1997
Fixed-charges coverage (times)	5.86	7.53	4.96	0.65	0.93
% debt in capital structure	36.8%	38.1%	38.7%	101.8%	131.0%
Cash flow/total debt (times)	0.17	0.27	0.28	0.04	0.06
Cash flow/capital expenditures (times)	1.70	2.41	2.07	1.71	2.68
EBIT ($ millions)	933	1,198	1,010	1,463	2,256
Net income ($ millions - bef extras.)	425	605	446	(714)	(58)
Operating cash flow ($ millions)	1,056	1,407	1,335	829	1,512
Electricity sales - billion of kWh	142.1	139.8	136.9	131.7	134.1

(1) 1999 consists of nine months. OPG + three months proforma allocation/DBRS estimates of Ontario Hydro results.

THE COMPANY

Ontario Power Generation Inc. is one of the successor companies of the former Ontario Hydro, with a diverse portfolio of 24,700 MW of installed generating capacity (excluding 6,200 MW generation capacity leased to Bruce Power until 2018). The Company is wholly owned by the Province of Ontario. Debt issued directly by Ontario Power Generation Inc. is not guaranteed by the Province.

RATING CONSIDERATIONS

Strengths: (1) The Company serves an attractive franchise area in Ontario, which stretches across a substantial east/west base. It has exposure to the highest population base in Canada and touches on the main mid west and eastern cities in the U.S. Detroit, Chicago and New York are major markets that it can serve, giving OPG the opportunity to take advantage of: (a) different weather patterns; (b) two different time zones; (c) markets where coal and gas are the prime raw material bases; and (d) the markets OPG can service are highly industrialized with significant per capita demand.
(2) Electricity generating costs are competitive with most markets served. The utility's hydro/nuclear base gives it a low variable cost structure, and it is cost competitive with most markets. It is in an extremely strong position to "trade" electricity.
(3) The balance sheet remains above average, with debt levels near 40% giving the Company financial ratios superior to most other utilities in North America.
(4) The Company after "divestitures" will have approximately 20,400 MW of generation capacity. Although its market share will be substantially reduced in the future, OPG will still be the leading generator of power in Ontario.
(5) The provincial government has capped the nuclear liability of the Company associated with long-term management of used fuel. OPG's maximum exposure is approximately $3.7 billion.

Challenges: (1) Under the current MPMF, fuel cost increases for coal and natural gas cannot be fully recovered due to the rate cap on roughly two-thirds of sales. This is presently squeezing earnings.
(2) The delays in returning Pickering A nuclear station to service impacts cash flows negatively. A full return should generate cash flow near $300 million annually, which today is a cash drain.
(3) Competition in the domestic market is growing, and the ability to influence electricity prices in Ontario is diminishing.
(4) Environmental concerns remain with respect to coal and nuclear. Disposal of nuclear waste and removal of SO_2, CO_2 and NOx in the coal area are ongoing challenges that will grow.
(5) Government ownership presently restricts the ability of the Company to issue equity capital, and to pursue investments outside the province to provide diversification.

RESTRUCTURING IN ONTARIO ELECTRICITY INDUSTRY

Under the industry restructuring which became effective April 1, 1999, five separate entities were created from the former Ontario Hydro. (1) OPG holds and operates all the generating assets. (2) Hydro One Inc. ("HO") holds and operates all the transmission and distribution assets. (3) Ontario Electricity Financial Corporation ("OEFC") is responsible for managing and retiring the outstanding debt and certain other liabilities of the former Ontario Hydro. Maturing debt will either be repaid or refinanced directly by the Government of Ontario. (4) Independent Electricity Market Operator ("IMO") is a non-profit corporation that will perform the central market operating functions. (5) Electrical Safety Authority ("ESA") is a non-profit corporation that will conduct electric installation inspections. The electricity industry in Ontario was initially scheduled to be open for competition in November 2000. However, market opening has been delayed to May 2002 since many market participants were not ready on time. All customers in Ontario will be able to choose their supplier when the market opens. The Province's industry restructuring legislation requires that OPG decontrols 4,000 MW of primarily fossil-based capacity within 42 months of open access. OPG has announced that it is accelerating the process through the decontrol of Lakeview (1,100 MW), Lennox (2,100 MW), Thunder Bay (300 MW) and Atikokan (200 MW), and four hydroelectric stations on the Mississagi river (500 MW). In addition, OPG is required to reduce its capacity to no more than 35% of the province's available supply (measured in MW) within ten years of market opening. The government has capped OPG's revenues at 3.8 cents per kWh on roughly two-thirds of its Ontario sales, subject to decontrol capacity reductions, for the four years following the opening up of the Ontario electricity. Any revenue in excess of the cap would be rebated pro rata to the consumers.

EARNINGS

Income statement (1) ($ millions)	12 mos. June 2001	Pro forma For years ended December 31 2000	1999	1998	1997
Total revenues	6,140	5,978	5,795	6,592	6,652
EBITDA	1,714	1,962	1,775	2,904	3,679
Dep. & amortization	781	764	765	1,441	1,423
EBIT	933	1,198	1,010	1,463	2,256
Net interest costs	138	140	179	2,177	2,314
Net income (loss) before extras.	425	605	446	(714)	(58)

(1) 1999 consists of 9-mos. OPG + 3-mos. proforma allocation/DBRS estimates of Ontario Hydro results.
1997-98 data incorporates DBRS estimates.

Steady growth in electricity sales volume and lower operating costs due to a reduction in pension expense, led to a 16% increase in EBIT in 2000. A decrease in the effective income tax rates in addition to the aforementioned positive attributes, improved net earnings to $605 million from $446 million year-over-year.

Outlook: Earnings in 2001 are expected to be squeezed due to increased coal costs, higher costs related to Pickering A restarts, increase in pension expense, and delay in market opening. However, earnings beyond 2001 are expected to grow materially over the next several years, based on the following assumptions. (1) Nuclear recovery costs are largely being expensed, and therefore operating costs should fall sharply after 2002, provided there is no delay/cost overruns in the Pickering A recovery. (2) The return to service of Pickering A units, should allow OPG to generate an additional 16 billion kWh of electricity per year. With this additional energy, power could be exported and/or replace more costly fossil-fuelled (about 1 cent per kWh higher generation cost) electricity generation, thereby reducing fuel costs. While the Province has capped OPG's annual power rates at about 3.8 cents per kWh for four years, for a majority of Ontario sales, the Company should be able to earn a premium on export sales and on Ontario sales not subject to the rate cap. Since it is a low cost producer relative to neighbouring U.S. utilities, import competition is not a material concern. (3) Debt retirements of $200 million or more annually, starting in 2001, should translate into lower interest costs, assuming there are no acquisitions.

Four factors could materially affect the above outlook. (1) The most significant risk is any delay in the scheduled return to active service of the four Pickering A units, and/or further operational problems related to the existing nuclear units currently in service. This would reduce cash flow $200 million per year. (2) Competitive pressures could result in a sharp decline in electricity prices. Should the price of electricity fall sharply to 2.8 cents per kWh, OPG would be close to its breakeven level in 2004. However, with a lower cost structure than neighbouring U.S. utilities, it is unlikely that 2.8 cents per kWh power would prevail for any length of time. (3) Asset sales as a result of the mandated capacity decontrol, which could reduce earnings and potentially increase competitive pressures within the province. (4) Increase in coal costs could materially affect earnings.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

Consolidated Cash Flow Statement	12 mos. ended June 2001	For years ending Dec. 31 2000	1999	Stress Testing Year 1	Year 2	Year 3
Net income before non-recurring, minority	425	605	446	380	380	378
Depreciation + amortization	781	764	765	771	761	751
Other non-cash adjustments	(150)	38	124	0	0	0
Operating cash flow	1,056	1,407	1,335	1,151	1,140	1,129
Less: decommissioning + waste disposal	490	457	361	550	550	550
Common dividends	184	205	155	570	200	200
Capital expenditures (net of contrib)	620	585	645	600	600	600
Gross free cash flow	(238)	160	174	(569)	(210)	(221)
Less: working capital changes	(110)	(331)	87	0	0	0
Free cash flow	(128)	491	87	(569)	(210)	(221)
Less: net acquisitions	0	0	0	0	0	0
Less: other investments	(287)	319	(33)	(370)	0	0
Plus: net debt	0	150	146	199	210	221
Plus: net common	0	0	0	0	0	0
Net change in cash	159	322	266	0	0	0
Gross debt in capital structure	36.8%	38.1%	38.7%	38.9%	39.5%	40.1%
EBITDA interest coverage	10.78	12.34	8.62	8.14	7.69	7.27
Cash flow/adjusted total debt	0.17	0.27	0.28	0.17	0.15	0.14

Financial Profile: Over the past two years, OPG operating cash flows were sufficient to cover its capital expenditures after dividends. Positive working capital changes of $331 million in 2000, boosted free cash flow to $491 million, and this helped maintain the financial ratios at above-average levels.

Outlook: OPG will likely have a free cash flow deficit in 2001 and 2002, as operating cash flows are not expected to be sufficient to finance the following: (1) approximately $400 million in cash payments to the nuclear waste management and decommissioning funds in each year; (2) a 35% dividend payout ratio; and (3) $0.8 billion - $1.0 billion of capital expenditures per annum. As a result, the Company plans to issue debt to fund the shortfall. The $370 million initial proceeds from the Bruce transaction are expected to be fully distributed to the government. An additional $225 million deferred payment will be applied to the segregated nuclear liability funds. OPG's free cash flow surplus should turn positive as the Pickering A units return to service and capital expenditures fall sharply after 2003. Maintaining a 35% dividend payout ratio would result in a substantial reduction in balance sheet leverage when capex moderates, assuming no further delays in the return to service of the Pickering A units, asset divestitures or material acquisitions. OPG is expected to manage the dividend payout to maintain a debt-to-capital ratio of about 40%.

Sensitivity Analysis:

DBRS stress tests financial results to measure earnings sensitivities and their impact on key debt ratios. Note that the assumptions used in this stress test are not based upon any information provided by the Company, or DBRS expectations. The business and financial condition of OPG is influenced by a number of factors including political and economical risks, market demand for energy, inflation, and other general and specific economic conditions in the Company's service areas, governmental policies, legislative and regulatory actions.

Using results for 12 months ended June 2001 as a proxy for the next three years and keeping all other costs constant, we reduced EBIT by 5% in Year 1 and remained flat in Years 2 and 3. In addition, DBRS assumed the Company would distribute the $370 million proceed from the Bruce transaction as a special dividend to the government in Year 1. Under this scenario, the Company would only be able to finance $1.2 billion of the accumulated $1.8 billion in capex in the stress test period. This would cause debt in capital structure to rise slightly.

DEBT MATURITY SCHEDULE

	2001	2002	2003	2004	2005
($ millions)	200	200	200	300	300

BANK LINES OF CREDIT

OPG has a $600 million in revolving credit facility to back up its commercial paper program. At June 30, 2001, $100 million of commercial paper was issued under the program.

Ontario Power Generation Inc.

Balance Sheet (1)

($ millions)	As at December 31			As at December 31	
Assets	2000	1999	**Liabilities & Equity**	2000	1999
Cash + short-term investments	900	243	Short-term debt/debt due 1 yr	354	4
Accounts receivable	968	930	A/P + accr'ds + other	1,406	1,145
Fuel	288	424	Current liabilities	1,760	1,149
Material + supplies	229	201	Long-term debt	2,469	2,672
Current assets	2,385	1,798	Subordinate long-term debt	750	750
Net fixed assets	12,932	12,902	Net waste mgmt liab	4,482	4,235
Def'd pension assets	641	516	Other liabilities	516	428
Other assets	52	27	Post employment benefits	997	959
Nuclear waste mgmt fund	781	367	Equity	5,817	5,417
Total	16,791	15,610	Total	16,791	15,610

Ratio Analysis (1)

	For years ended December 31			
Liquidity Ratios	2000	1999	1998	1997
Current ratio	1.36	1.56	0.27	0.20
Accumulated depreciation/gross fixed assets	6.6%	2.9%	31.2%	28.8%
Cash flow-waste funding/total debt (incl. debt equiv.)	0.27	0.28	0.04	0.06
Cash flow/capital expenditures	2.41	2.07	1.71	2.68
Cash flow-w. f./capital expenditures	1.62	1.51	1.81	2.78
Cash flow-w.f.-dividends/capital expenditures	1.27	1.27	1.81	2.78
% debt in the capital structure (incl. debt equiv.)	38.1%	38.7%	101.8%	131.0%
Average coupon on long-term debt	5.93%	5.93%	-	-
Common dividend payout (before extras.)	33.9%	34.8%	0.0%	0.0%
Coverage Ratios (2)				
EBIT interest coverage	7.53	4.96	0.65	0.93
EBITDA interest coverage	12.34	8.67	1.28	1.51
Fixed-charges coverage	7.53	4.96	0.65	0.93
Earnings Quality / Operating Efficiency				
Fuel costs/revenues	21.3%	17.0%	15.5%	10.4%
EBIT margin	20.0%	17.4%	22.2%	33.9%
Net margin (before extras.)	10.1%	7.7%	-10.8%	-0.9%
Return on avg. common equity (before extras.)	10.8%	8.2%	-	-
Profit returned to government (before extras.)	72.2%	78.1%	-54.9%	129.3%
GWh sold/employee	9.3	8.6	7.4	7.3

(1) 1999 consists of nine months OPG + three months pro forma allocation/DBRS estimates of Ontario Hydro results. 1997-1998 ratios incorporate DBRS estimates.

(2) EBIT includes interest income. Interest expense before capitalized interest, AFUDC and debt amortizations.

Operating Statistics		For years ended December 31				
Electricity Sold - Breakdown		2000	1999	1998	1997	1996
Domestic		135,800	132,400	128,700	127,700	130,000
Interconnected sales (exports)		4,000	4,500	3,042	6,396	6,112
Total sold - GWh		139,800	136,900	131,742	134,096	136,112
Growth in electricity sales		2.1%	3.9%	-1.8%	-1.5%	
Generation						
Hydro	24%	7,255	7,255	7,328	7,328	7,328
Nuclear (1)	45%	13,864	13,864	13,864	13,395	13,395
Coal	25%	7,560	7,560	7,560	7,560	7,560
Oil (2)	7%	2,140	2,140	2,140	2,140	2,140
Installed capacity (megawatts)	100%	30,819	30,819	30,892	30,423	30,423
Energy generated (GWh)						
Hydroelectric	24%	34,000	33,631	31,900	36,365	37,561
Nuclear	43%	60,000	61,420	59,880	70,209	77,675
Fossil	30%	42,000	36,050	34,200	24,443	19,042
Gross energy generated (3)	97%	136,000	131,101	125,980	131,017	134,278
Net purchases (4)	3%	3,800	5,799	5,762	3,079	1,834
Total sold (GWh)	100%	139,800	136,900	131,742	134,096	136,112
Export Interconnections (3)						
Hydro-Québec		530	530	530	530	530
Manitoba Hydro		300	300	300	300	300
U.S. - New York		2,450	2,450	2,450	2,450	2,450
- Michigan (4)		2,400	2,400	2,400	2,400	2,400
- Minnesota		150	150	150	150	150
Total (megawatts)		5,830	5,830	5,830	5,830	5,830
Export capacity % of gen. capacity		18.9%	18.9%	18.9%	19.2%	19.2%

(1) Includes Pickering A 2,060 MW laid-up for refurbishment in 1999 and 3,076 MW leased to Bruce Power effective May 2001.
(2) Two units converted to dual fuel (oil/gas) in 1999, remaining two units converted by end of 2000.
(3) Maximum winter export capability. Maximum summer export capability 5,668 MW as of June 2001.
Maximum winter import capability 5,558 MW as of June 2001 (5,758 MW after August 2001, summer import capability 5,132 MW as of June 2001 (5,397 MW after August 2001).
(4) Increases to 2,450 MW effective August 2001.

Appendix

IMPLICATIONS OF DECONTROL

	2000A	2005F	OPG Assumptions
Hydro	7,300 MW	6,800 MW	4 stations on Mississagi river (500 MW)
Nuclear (in-service)	8,700	7,700	Bruce B decontrolled, Pickering A returns to service
Coal	7,600	5,900	Lakeview, Thunder Bay & Atikokan decontrolled
Dual fuel (oil/gas)	2,100	-	Lennox 2,100MW decontrolled
Total operating	25,700	20,400	
Pickering A (1)	2,100	-	
Bruce A (1)	3,100	-	Bruce A 3,100 MW decontrolled in May 2001
Total installed	30,900 MW	20,400 MW	

(1) Currently laid up for refurbishment.

Earnings/Cash Flow Implications

- Decontrol of higher cost coal facilities should help future profitability and could reduce OPG's environment-related risks
- Earnings and cash flows should increase when Pickering A refurbishment is complete and units return to service. OPG may decontrol capacity through sale, lease or asset swaps outside of Ontario
- Disposition of proceeds: both the Provincial Government and OPG have stated that re-capitalization of OPG's balance sheet will occur to maintain debt-to-capital at about 40%

The Province's industry restructuring legislation requires that OPG decontrol 4,000MW of primarily fossil-based capacity within 42 months of open access. OPG has announced that it is accelerating the process through the decontrol of Lakeview (1,100 MW) and Lennox (2,100 MW), Thunder Bay (300 MW) and Atikokan (200 MW), and four hydroelectric stations on the Mississagi river (500 MW). The mandated decontrol program is expected to introduce competition into the Ontario market.

FUTURE PRICING OF ELECTRICITY IN ONTARIO

Under open market conditions, with interties to the U.S., DBRS expects that wholesale electricity prices in Ontario may coincide closely with electricity prices in the adjacent U.S. states. Prices will be influenced in the summer months by the spot markets in Michigan; and/or influenced in winter by markets in the area around New York. Prices will be volatile when certain generators are taken out of service for maintenance, causing fluctuations in supply. The interties between Ontario and the U.S. are large enough to bring some convergence between Ontario and U.S. prices.

The prices for electricity in Ontario will be influenced by the value of the Canadian dollar as well, plus interconnection constraints. The interconnection capacity between Ontario and neighbouring markets is as follows:

	Limit on Exports (MW)	Limit on Imports (MW)	Power Pool
Michigan	2,450	1,765 in Summer 1,800 in Winter	ECAR
New York (at Niagara Falls)	1,950 in Summer 2,050 in Winter	1,450 in Summer 1,750 in Winter	New York Power Pool
New York (eastern Ontario)	400	400	New York Power Pool
Quebec	530	1,394 in Summer 1,408 in Winter	
Minnesota	150	100	MAPP
Manitoba	288 in Summer 300 in Winter	288 in Summer 300 in Winter	MAPP

*Based on thermal ratings, 75% of pre-load, 0-4 km/hr wind speed, 30 degrees Celsius ambient temp for Summer limits and 10 degrees Celsius ambient temp for winter limits. **Summer limits apply from May 1 to October 31. Winter limits apply from November 1 to April 30.

The intertie capacity levels are nominal, and not additive. Thermal limits, congestion, line outages, loop flows at a point in time, stability limits, system configuration and voltage can influence capacity at any one point in time. It is impossible to export the amounts shown at the same time.

Accordingly, Ontario's simultaneous import capacity at any one point in time is limited to 5,000 MW to 5,800 MW. Export capability is limited to 5,800 MW to 5,900 MW. In a given year, exports could be 22 billion kWh once the Pickering A units are operating, depending on: (1) the number and location of generating units; (2) the flow of power in the U.S.; and (3) temperatures on the transmission lines and wind speed. Hydro One Inc. is obligated to use its best efforts to raise interconnections by 2,000 MW with New York, Michigan and Quebec within three years following the opening up of the electricity market (scheduled for May 2002), subject to governmental and regulatory approvals and environmental assessments. This would raise import/export capacity by 12 billion kWh (six billion kWh with Quebec, four billion kWh with Michigan, two billion kWh with New York) to 36 billion kWh.

Ontario exports averaged 7.5 billion kWh between 1994-1998. Since 1998 with Pickering A and Bruce A laid up/lease, OPG has become a net buyer of three to six billion kWh of electricity.

Export Markets

Quebec: Hydro-Québec ("HQ") generates low-cost hydroelectric generation, and is, expected to enter Ontario as a competitor over time. HQ benefits from substantial storage capacity and, with interconnections into New Brunswick, New England, New York and Ontario, Hydro Quebec will be a major player in the northeast North American electric market. Interconnections and differing technology with Ontario presently limit power flows substantially, but eventually this will change.

New York Power Pool: OPG has participated in this market since November 1999. New York Power Authority generates low priced power for municipalities and public authorities in New York using the St. Lawrence River as a major base. However, much of the generation plant is old, and the market area itself is a high priced market. Nevertheless, excess power can be priced at the margin and exported into Ontario. The New York market is power short in winter and will influence power rates in Ontario in the winter, as Ontario exports into this market.

New England Independent System Operator: Gas supply to this region, particularly from the Sable Island field is encouraging new merchant plant construction. The market is one of the highest cost markets for electricity in the U.S., and a significant load of merchant energy has been announced for development.

Pennsylvania/New Jersey/Maryland/ISO and the Mid-Atlantic Area Reliability Council: This market operates as an independent system operator with non-discriminatory wheeling fees. Severe transmission constraints restrict the flow of power and prices vary. Electricity from Ontario can be shipped into the eastern part of this market, provided transmission capacity is available. This is a coal-based generation market. The Niagara interconnection is just a few miles away from the northwest boundary of this Pool, which will be secondary for Ontario to the New York and Michigan pools.

East Central Area Reliability Coordination Agreement (ECAR): The generation in this market is 90% coal-based, and generating costs in Michigan are higher than those in Ontario. Detroit Edison's average electricity rates, for example, are US7.6¢ per kWh retail, versus a US7.0¢ national average, and about US6¢ in Ontario. There is a power shortage in the summer in this market, and power must be imported. Michigan represents an ideal market for Ontario, with 2,450 MW of export interconnection. The Michigan Co-ordinating System (MCR), is part of ECAR, with Ontario in the last year of a six-year seasonal sales contract with MCR. The power shortage in summer in this market means that prices here could influence power prices in Ontario. ECAR's area includes the states of Michigan, Indiana, Ohio and Kentucky, and represents one of the largest electricity markets in the U.S. The East Central Area, which includes Michigan, Indiana, Ohio and Kentucky, is one of the largest and most attractive markets for OPG. The northeast, especially the North East Power Pool, in reaction to high prices is experiencing an oversupply of power projects. This should begin to affect prices by 2005 as these projects become operational.

Mid America Interconnected Network (MAIN): This area gets 26% of energy from nuclear, where, with retiring stations, new capacity is needed. The area has a strong seasonal bias for power demand in the summer which could be attractive to Ontario. The MAIN market area will likely have an influence on power rates in Ontario in the summer, and includes Illinois, Wisconsin and part of Missouri.

Mid-Continent Area Power (MAPP): Manitoba Hydro is an important player in this market, and has important firm power contracts with utilities. A purchase agreement with Ontario uses all the interconnection capacity of 250 MW until 2003, thereby eliminating competition until this time period. There is also a small interconnection from Ontario into Minnesota equal to 150 MW (exports from Ontario) and 100 MW (imports to Ontario). On the whole, the MAPP power pool will not be an important market for Ontario, unless transmission capacity is expanded.

MARKET OUTLOOK FOR ELECTRICITY

The market outlook for electricity is as follows:

(1) Manitoba's limited interconnection capacity will limit competition with OPG.
(2) Initially, sales in Ontario will primarily be on a spot basis with bilateral agreements with end customers increasing over time.
(3) U.S. electricity prices will help establish electricity prices in Ontario, as arbitrage between the two markets occurs. Michigan and area, which is power short in the summer, will influence power rates in Ontario in the summer. The winter power short New York market will have the greatest influence on Ontario rates in the winter. Ontario's summer demand is now almost equal to winter demand.
(4) Prices should show substantial fluctuations between on-peak and off-peak demand, particularly at the beginning of the open market.
(5) Hydro Quebec will have growing influence in the Ontario market as more interconnection ties are added.

FUTURE SUPPLY FROM OPG

Supply is expected to rise by about 16 billion kWh by 2003, when Pickering A's 2,100MW of power comes on stream. Power produced in Ontario will rise from near 140 billion kWh to near 150 billion kWh, with about 22 billion kWh exported with present tie-line interconnections. By 2002, with the return to service of Pickering A and the decontrol of Lennox (oil/gas), Bruce (nuclear) and other coal capacity (to meet the initial requirements of 4,000 MW of fossil decontrolled), OPG's installed generating capacity is estimated to be 35% hydro, 37% nuclear, and 28% coal. Through 2001, net power generated should be equal to 140 billion kWh, until Pickering A nuclear starts generating. Fossil generation near 39 billion kWh could be reduced by six billion kWh as Pickering A generates up to 16 billion kWh. The current in-service capacity (excl. Bruce and Pickering A) is 28% hydro, 29% coal, 34% nuclear and 8% dual fuelled (oil and natural gas).

NUCLEAR GENERATION CAPACITY

The Candu reactors operated by OPG, which burn natural uranium are as follows:

Site	Capacity (MW)	%	In Service Date	2000 capacity factor	2000 Prod. (B of kWh)	Present Status	Retirement Date
Darlington	4 x 881	46	1990-93	86%	26.6B	In service	2022-2025
Pickering A (1)	4 x 515	27	1971-73	-	(0.1)	Lay up	2011-2013
Pickering B	4 x 516	27	1983-86	56%	10.1	In service	2013-2016
Total	7,648	100					

(1) Pickering A has been retubed and the boilers have been well maintained. Operating life has been extended to 40 years. Renovations in the 1998-2002 period have been estimated to cost $1.1 billion.

OPG has 7,648MW of nuclear generation capacity, with four of the 12 units presently not operating. The first of the four units at Pickering A is expected to come on stream in early 2002 as it is refurbished and the necessary safety issues are resolved. The life of the reactors is generally 25 years, but this can be potentially extended by re-tubing and replacing the boilers. This has happened at Pickering A. Darlington has a capacity factor of near 85% which is in line with the 87% US average. However, in 2000, Pickering B was below 60%, primarily due to a scheduled vacuum building outage. Darlington units near 900 MW per generator are the largest units, while Pickering A near 500 MW is only about 60% of the capacity of the Darlington units. Darlington's variable costs are low, ranking it among the most efficient in the world. OM&A in nuclear plants is currently high due to costs related to nuclear refurbishments (these costs are being expensed as incurred). As the recovery program winds down, OM&A should fall materially. With replacement of pressure tubes and steam generators, the life of the reactors could be extended beyond their nominal lives.

Commentary: Nuclear-based generation has two main advantages. (1) Marginal costs of operating the nuclear plants (defined as cash costs needed to produce electricity and include operating and maintenance costs) are relatively low (under US3¢ per kWh). This results in very good cash flow generation, as long as nuclear plants are operating. Canadian reactors are budgeting for mid-80% capacity factor, with historical problems in the pressure tubes and heavy water leaks. (2) Nuclear reactors do not emit nitrogen, sulphfur or carbon dioxide related impurities, and in this sense are environmentally friendly. (However, fuel disposal remains a problem). Challenges include: (1) Very expensive decommissioning costs after expected lives in the 25-40 year range. (2) No permanent storage has yet been found for the spent and highly radioactive fuel. (3) Design and operating problems may reduce the life of plant and equipment. In the case of the Candu reactors, this involves problems with pressure tubes, boilers, and heavy water leaks. (4) There is a major loss of revenue and cash flow whenever a reactor closes unexpectedly for safety-related issues.

HYDRO GENERATION

OPG produces 31.6 billion–38.8 billion kWh of electricity from hydro, averaging about 35.0 billion kWh, equal to about one-quarter of energy generated. The exact amount depends on rainfall. Stations provide 7,255 MW of generation capacity, about 40% larger than Manitoba Hydro. Largest stations are run of the river plants located on the Niagara and St. Lawrence rivers. Many stations were built in the early 1900's to provide electricity for mining and forestry companies. The small Hydro division consists of 26 plants (1-12MW) is operated as one division, but has only 1,057 MW of capacity. A breakdown of hydro generation capacity is as follows:

Plant	Capacity (MW)	%	Units	Energy (B of kWh)	%
Niagara Falls Plant	2,244	31	38	12.2	36
Ottawa/St. Lawrence Plants	1,928	26	44	10.8	32
Madawaska/Abitibi/Mattagami/Mississagi Plants	2,081	28	51	5.7	16
Small Hydro Division	1057	15	116	5.7	16
Total	7,310	100	249	34.4	100

There are 249 hydroelectric dams across Ontario, ranging in age from eight to 100 years, with heights of six feet to 400 feet. Hydro generation has variable costs of roughly 0.70¢ per kWh and a 53% load factor over time. Modernization is continuing and this will improve reliability with OM&A and capital spending near $100 million each.

FOSSIL GENERATION

Fossil generation for OPG breaks down as follows:

Station	Units	In Service Date	Net Capacity (MW)	%	Net energy (B/kWh)	%	Est. Retirement Date
Nanticoke	8	1973-1978	3,920	40	23.5	53	2015
Lambton	4	1969-1970	1,975	20	12.4	29	2010/2020
Lakeview	4	1962-1969	1,140	12	2.8	7	2005
Lennox	4	1976-1977	2,140	22	1.2	3	2016
Thunder Bay	2	1981-1982	310	3	1.6	4	2021
Atikokan	1	1985	215	2	1.0	2	2025
Total			9,700	100	42.4	100	

The six fossil plants are cost competitive. With the exception of Lennox, the fossil plants are all coal-based. All four of the units at Lennox burn natural gas or heavy fuel oil. Typically, OPG can service average demand in the province (about 16,000 MW) with nuclear and hydro. It needs fossil-generated power for peaking purposes (24,000 MW). Thus, as they are mainly used for peaking, the capacity factor of fossil fuel plants is relatively low, in the 40%-50% range for the major plants including 12% for Lennox and 34% for Lakeview. All plants have access to water (for coal supply and cooling) and transmission lines are in place and are close to end markets. Production of electricity from fossil, near 39 billion kWh, is predicted until Pickering A starts up in 2002, when fossil energy generation is expected to fall six billion kWh. Variable costs for OPG's fossil plants are low, making these plants very competitive with other thermal plants. Both OM&A and fuel costs are relatively high, compared to hydroelectric and nuclear generation with large component of fuel costs being transportation costs. OPG is mandated to reduce its generation capacity by 4,000 MW of primarily fossil capacity within 42 months of open access. It is intending to dispose of the Lakeview, Lennox, Thunder Bay and Atikokan units to reduce capacity by 3,805 MW, having already leased the Bruce nuclear generating station.

Current capital projects include adding installations to burn low sulphur Powder River Basin coal at Nanticoke.

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 the Utility.)

Current Report: September 4, 2001
Previous Report: September 29, 2000

RATING

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Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Corporate Long-term Debt

RATING HISTORY

	Current	2000	1999	1998	1997
Corporate Long-term Debt	"A"	"A"	A (low)	A (low)	A (low)

COMMENTARY

Saskatchewan Power Corporation's ("SaskPower" or "the Utility") rating is a flow-through of the long-term debt rating of the Province of Saskatchewan, as the Utility's securities are direct obligations of the Province. Earnings in 2000 continued their stable performance, and have been in the $120 million-$140 million range over the past five years. In 2000, record export of power, mainly to Alberta at sharply higher rates (near 7.33¢ KWH), offset the effects of substantially increased costs for natural gas, coal and purchased power. With rate increases for 2001 and lower energy costs (natural gas, coal), earnings should remain in the traditional range. However, the risk is that gas prices will not remain low enough throughout the remainder of 2001 to offset the higher prices incurred during the earlier months, which could result in lower earnings. The balance sheet is also stable. The Utility has the strongest balance sheet of any of the publicly owned utilities, and has the capacity to spend about $200 million-$250 million on capex annually, and still keep debt levels unchanged. DBRS stress tested the balance sheet for 20% earnings declines and capex near $200 million, and the financial ratios remained either stable or actually improved. Unless there is a substantial change in growth philosophy in the future, the Utility has the capacity to maintain a stable balance sheet, with financial ratios approaching that of investor-owned electric utilities. The Utility is addressing the need for future capacity by using joint ventures and third party sources for power. This will restrict future borrowing needs, and help preserve the balance sheet. The Utility burns low BTU thermal coal in facilities which are older, and has relatively high variable costs, compared to utilities in western Canada. However Saskatchewan Power is integrated, (transmission, distribution and generation) and is quite cost competitive in the Saskatchewan marketplace.

CONSIDERATIONS

Strengths:

- Debt securities are direct obligations of the Province
- Limited interconnections reduce competitive pressures
- Key customers locked in with long-term contracts
- Relatively strong balance sheet, proactive debt reduction
- PPAs, repowering of existing plant, joint ventures addressing growing power needs

Challenges:

- Investments to meet growing demand load could potentially pressure key debt ratios
- High variable costs, partially due to coal based plants/low population density of service region
- Concentrated customer base; earnings sensitive to economic cycle
- Over half of gross debt denominated in U.S. dollars

FINANCIAL INFORMATION

For years ended December 31

	2000	1999	1998	1997	1996	1995
EBIT interest coverage (times)	1.85	1.86	1.79	1.68	1.69	1.37
Net debt in the capital structure	55.7%	56.3%	58.9%	61.0%	64.3%	67.2%
Cash flow/total debt (times)	0.18	0.17	0.17	0.17	0.16	0.11
Cash flow/capital expenditures (times)	1.40	1.47	2.28	2.22	3.20	1.40
Net income ($ millions)	126	114	140	132	139	80
Operating cash flow ($ millions)	281	256	285	295	291	220
Electricity sales (millions of kWhs)	17,049	16,225	16,187	15,608	15,064	14,383
Electricity revenues (cents per kWh sold)	6.33	5.90	5.81	5.78	5.78	5.82
Variable costs (cents per net gen kWh sold)	4.01	2.94	2.68	2.47	2.28	2.58
Fixed costs (cents per net gen kWh sold)	2.50	2.39	2.48	2.69	2.78	2.82
Average coupon on long-term debt	8.95%	9.11%	9.20%	9.34%	9.47%	9.62%

THE COMPANY Saskatchewan Power Corporation, a Crown corporation of the Province of Saskatchewan, generates and distributes electricity in Saskatchewan.

CONSIDERATIONS

Strengths: (1) *Debt securities are direct obligations of provincial government* - The Utility is responsible for the repayment of principal and interest. As such, the rating assigned to SaskPower is a flow-through of the rating of the Province of Saskatchewan.
(2) *Limited interconnections minimize competitive pressures* - Given the costs of expanding inter-tie capacity, this situation is unlikely to change quickly. This limitation also hinders SaskPower's ability to import electricity to address power needs.
(3) *Key customers locked in with long-term contracts* - The Utility has been able to negotiate long-term contracts with some of its major customers. The reduction of cross-subsidizations between residential/farm and industrial customers has allowed for reductions in rates for energy intensive companies, discouraging some industrial customers from plans to self-generate power.
(4) *Relatively strong balance sheet* - SaskPower's 56% debt-to-capital ratio compares very favourably to the government-owned utility average of 70%. Although still weak compared to the private sector, which typically carries less than 50% debt, SaskPower financial leverage is among the lowest of all government-owned utilities. The Utility is expected to continue to generate sufficient cash flows to finance capital expenditures, however, does not expect to generate sufficient surpluses to reduce outstanding debt levels in the current fiscal year.
(5) *PPAs, repowering of Queen Elizabeth plant and joint ventures addressing growing demand load* - The Utility has addressed growing power needs by concluding a 25-year purchase power agreement at favourable rates, for the power from a co-generation plant jointly owned by TransAlta Corporation and Husky Oil Limited. The 210-MW Meridian plant became operational in December 1999. Other projects underway that will address growing demand load over the next few years include the re-powering of an existing thermal plant (Queen Elizabeth) that will increase capacity by 150-MW by July 2002, and a joint venture (with ATCO Power Ltd.) for the 228-MW Cory Cogeneration Project that is scheduled to become operational late in 2002.

Challenges: (1) *Investments to meet growing demand load could potentially pressure key debt ratios* - In addition to new plants to address growing demand load, the Utility will have to make a decision over the next few years on the refurbishment of a number of plants that are nearing the end of their design life over the next five to ten years. (However, this should not severely pressure the future balance sheet.)
(2) *High cost operator* - The Utility has among the highest variable costs of all government utilities due to two material factors. (a) About 57% of generating capacity is coal-based, another 13% is gas-fuelled and 30% of capacity is hydro-based, when water is available. Hydro accounts for only 19.7% of gross energy generated in 2000. (b) The service region (a large geographic area) has a low population density, which raises operating costs.
(3) *Concentrated customer base* - Industrial customers (including oilfields) account for about 36% of domestic power sales, which makes the Utility's earnings sensitive to economic cycles.
(4) *Sensitivity to exchange rates* – About 56% of gross outstanding debt is denominated in U.S. dollars. With almost no U.S. dollar revenue, the Utility is very sensitive to changes in the value of the Canadian dollar.
(5) *Future environmental risks* - Given that about 57% of current installed capacity is coal-based, the Utility must manage future environmental risks associated with changes in emission standards.
(6) *Rate rebalancing required to more accurately reflect the cost of service* - Farm/rural customer rates account for only 91% of the cost of service, while urban residential customer rates account for 94% of the cost of service. The cross-subsidization between residential/rural and industrial/commercial rates could make it difficult to retain industrial customers if open competition were to be introduced in Saskatchewan.
(7) *Relatively high weighted average coupon on long-term debt* - Roughly 44% of SaskPower's gross outstanding debt is in Canadian dollars and averages 10.26%, thereby resulting in high interest costs.

EARNINGS

As of December 31

($ millions)	2000	1999	1998	1997	1996	1995
Revenues	1,101	977	953	915	884	847
EBITDA	455	472	496	515	524	460
EBIT	290	322	343	343	364	306
Net interest expense	157	173	192	204	216	224
Net income	126	114	140	132	139	80

Net income for 2000 was basically flat relative to 1999, with the increase in income related to lower interest costs. The performance was quite creditable when one considers the fact that energy costs exploded in 2000, while domestic rates remained unchanged. In addition, expensive outside power purchases doubled to 3.6 billion kWh, due to several power station overhauls and maintenance. Coal costs rose by $22 million or 15%, natural gas prices grew $20 million or 42% over 1999, and imported power costs grew $18 million or 36%. However, total generation grew by 1.256 billion kWh or 7%, while sales grew to 17.0 billion kWh or 5.2% including purchased power. Specifically (a) export volume mainly to Alberta grew 42.5% to 1.143 billion kWh; (b) oilfield energy used grew 15.9%; and (c) average prices received for export volumes were a near record 7.55¢/kWh, versus 4.61¢/kWh the prior year. Lastly, the allowances for depreciation were up by 10% due to full-year depreciation of SAP system and one-time equipment write-offs. Thus, higher electricity volumes sold specifically for export, where prices were record-high, substantially offsetting higher energy costs and flat domestic electricity rates.

Outlook: Earnings should continue to be stable in the future. Volume sales will likely not continue to grow at 2000's rate of 5.2%, and prices received for export electricity may continue to fall. However, natural gas costs are down sharply which will reduce generation costs. The approval of a 2.0% rate increase, in April 2001, should help future revenue. Earnings have ranged between $115 million-$140 million per year over the past five years, and this is unlikely to change.

REVENUES

The 5.2% revenue growth in 2000 was led by growth in exports and oilfield accounts, while domestic rates remained unchanged. Farm accounts, which are heavily subsidized, now account for under 10% of total revenue.

Customer Sector	Revenues - $ millions			Energy Sales – billions of kWh			Unit Revenues – cents/kWh sold		
	2000	1999	1998	2000	1999	1998	2000	1999	1998
Residential	208	207	203	2.337	2.315	2.266	8.90	8.94	8.96
Commercial	244	236	238	3.408	3.267	3.288	7.16	7.22	7.24
Oilfields	106	95	94	1.505	1.299	1.241	7.04	7.73	7.57
Key accounts	243	225	234	6.164	6.033	6.287	3.94	3.90	3.72
Farm	100	100	97	1.305	1.300	1.262	7.66	7.69	7.69
Other	(1)	2	2	(53)	0.014	0.034	1.89	14.29	5.88
DOMESTIC	900	865	868	14.666	14.228	14.378	6.14	6.08	6.04
Reseller + export	180	92	72	2.383	1.997	1.809	7.55	4.61	3.98
TOTAL	1080	957	940	17.049	16.225	16.187	6.33	5.90	5.81
Annual increase	12.9%	1.8%	4.2%	5.2%	0.2%	3.7%			

FINANCIAL GUIDELINES

	DBRS Calculation		Long-term	As calculated by SaskPower					
Ratio	2000	1999	Targets(3)	2000	1999	1998	1997	1996	1995
Debt in capital structure	55.7%	56.3%	50%	56%	56%	59%	61%	64%	66%
Interest coverage (1)	1.85X	1.86X	2.0X	1.80X	1.63X	1.69X	1.61X	1.64X	1.41X
Capex funded internally (2)	136%	152%	130%	100%	109%	100%	119%	219%	114%
Avg return on equity	10.3%	12.3%	13%	10.3%	9.9%	12.7%	12.7%	14.1%	8.6%
Avg return on capital	N/A	N/A	11%	10.3%	10.1%	11.5%	11.5%	12.1%	10.2%

(1) DBRS excludes capitalized interest, AFUDC and debt amortizations in the calculation while SaskPower includes these items.
(2) DBRS: Operating cash flows after working capital/Capital expenditures net of contributions. SaskPower: Cash flows after working capital less (dividends and sinking fund installments) plus customer contributions divided by capital expenditures net of AFUDC.
(3) Long-term targets set by SaskPower.

SaskPower continues to work towards meeting long-term financial targets. While the Utility's balance sheet is among the strongest of any government-owned utility, SaskPower is still below target in most categories.

FINANCIAL PROFILE

	Actual Data		**Stress Testing Data**		
	2000	1999	Year 1	Year 2	Year 3
Earnings	126	114	100	100	100
Depreciation/amortization	155	142	160	170	180
Operating cash flow	281	256	260	270	280
Capex	210	182	200	200	200
Dividends	68	67	68	68	68
Gross free cash	3	7	(8)	2	12
Working capital	(7)	9	(8)	(8)	(8)
Net free cash flow(1)	(4)	16	(16)	(6)	4
Change in net debt	12	(121)	16	6	(4)
% debt in capital structure	55.7%	56.3%	55.1%	54.5%	53.7%
EBIT interest coverage (2)	1.85x	1.86x	1.74	1.77	1.77
Cash flow/debt	0.18	0.17	0.17	0.17	0.18

(1) Include cash and short-term investments
(2) Interest costs estimated at $135, $130, $120 million , for the years 2001-03

Financial Profile

The Utility has the strongest balance sheet of any of the Canadian government-owned utilities except Ontario Power Generation. The key financial ratios come close in strength to those of the private sector, and superior to most publicly owned utilities. The ability of the Utility to continue to finance capex internally is keeping financial ratios stable, and little change in future financial ratios is expected.

Outlook: The Utility has some of the oldest thermal based plants and equipment in Canada, and this increases the need for maintenance and refurbishment. However, utilizing joint venture agreements for future plant development and third party power sources to meet excess demand, future capital expenditures should be well within the capacity of the Utility to finance.

Stress Testing

DBRS decreased income levels to $100 million and maintained capex at $200 million, to simulate a "realistic" worst case scenario of performance. Traditionally, the Utility has been able to maintain income at the $120 million-$140 million level. The results show that even under this scenario, and maintaining its dividend, the Utility can fund capex internally. Financial ratios are maintained at stable levels, or actually improve slightly even with a 20% earning decline. Thus, the future balance sheet of the Utility has substantial flexibility. Unless the Utility aggressively changes growth policies, few financial pressures are expected in the future for SaskPower.

DEBT MATURITY SCHEDULE & SINKING FUNDS

The minimum sinking fund installments and debt retirement requirements for the next five years are as follows ($millions):

	2001	2002	2003	2004	2005
Sinking funds	10	13	13	12	12
Debt retirement	-	-	148	58	72
Sinking Funds	10	13	161	70	84

PROVINCE OF SASKATCHEWAN

The Province of Saskatchewan's (the "Province") long-term and short-term ratings are confirmed at "A" and R-1 (low), respectively, both with Stable trends. The rating continues to reflect: (1) the track record of disciplined management and sound fiscal results; (2) good control over nominal debt and declining debt as a percentage of GDP; (3) a more diversified economic base; and (4) a portfolio of key assets generating strong revenues.

The Province fared well in 2000-01, taking advantage of booming energy prices, strong external demand and rising consumer confidence to post 3.4% real GDP growth and a $345 million DBRS-adjusted surplus. Despite a struggling agricultural sector, the upward economic trend is projected to continue in 2001-02 with real growth forecast at 2.2%.

Fiscal results are projected to be weaker, though, due to declining resource revenues and increased spending, especially on health and agriculture, forcing the Province to rely on its Fiscal Stabilization Fund to balance its budget. Since DBRS excludes from budget estimates transfers to or from the Fund (as part of DBRS's adjustments), the balanced budget presented by the Province for 2001-02 translates into a deficit of $331 million on a DBRS-adjusted basis.

While a sound financial profile is maintained, challenges remain, the most significant being a relatively high dependence on the agricultural and natural resource sectors, which introduces volatility in economic and fiscal performance. The Province must also deal with substantial spending pressures from its health-care sector, whose importance has been growing consistently over the past decade. A moderately high debt burden (at 37.1% of GDP), sustained inter-provincial out-migration and the volatility of equalization payments add to the challenges faced by the Province.

Saskatchewan Power Corporation

Balance Sheet

($ millions)

Assets:	2000	1999	1998	Liabilities & equity:	2000	1999	1998
	As at December 31				As at December 31		
Cash + equivalents	68	45	24	Short-term debt	0	55	60
Accts + notes receivables	153	120	121	A/P + accr'ds	219	178	177
Inventories	105	91	93	Current liabilities	219	233	237
Current assets	326	256	238	Other liabilities	294	291	277
Other assets & deferred costs	127	111	198	Long-term debt	1,571	1,481	1,576
Net fixed assets	2,879	2,829	2,794	Shareholders equity	1,248	1,191	1,140
Total	3,332	3,196	3,230	Total	3,332	3,196	3,230

Ratio Analysis

For years ending December 31

Liquidity Ratios	2000	1999	1998	1997	1996	1995	1994	1993
Current ratio	1.49	1.10	1.00	1.06	0.81	0.72	0.54	0.66
Accumulated depreciation/gross fixed assets	38.9%	37.5%	36.0%	34.3%	32.6%	30.5%	28.4%	27.1%
Cash flow/total debt	0.18	0.17	0.17	0.17	0.16	0.11	0.10	0.09
Cash flow/capital expenditures (1)	1.40	1.47	2.28	2.22	3.20	1.40	0.99	0.76
Cash flow-dividends/cap. expenditures (1)	1.06	1.09	1.24	1.65	2.60	1.10	0.79	0.45
% Debt in the capital structure	55.7%	56.3%	58.9%	61.0%	64.3%	67.2%	67.8%	68.9%
Average coupon on long-term debt	8.95%	9.11%	9.20%	9.34%	9.47%	9.62%	9.54%	9.53%
Common equity in capital structure	44.3%	43.7%	41.1%	39.0%	35.7%	32.8%	32.2%	31.1%
Common dividend payout (bef extras.)	54.8%	44.1%	55.0%	54.5%	53.5%	69.2%	56.8%	71.2%
Coverage Ratios (2)								
EBIT interest coverage	1.85	1.86	1.79	1.68	1.69	1.37	1.41	1.36
EBITDA interest coverage	2.90	2.73	2.58	2.52	2.43	2.05	2.04	2.00
Fixed charges coverage	1.85	1.86	1.79	1.68	1.69	1.37	1.41	1.36
Earnings Quality / Operating Efficiency								
Power purchases/revenues	6.3%	5.2%	4.7%	2.3%	1.4%	0.6%	1.5%	1.1%
Fuel costs/revenues	26.7%	18.3%	17.4%	16.6%	15.2%	15.6%	15.2%	14.5%
Operating margin	24.0%	30.5%	32.4%	33.7%	37.8%	32.5%	33.2%	32.6%
Net margin (before extras.)	11.4%	14.6%	14.7%	14.4%	16.1%	9.2%	10.1%	9.6%
Return on avg equity (bef extras.)	10.3%	12.3%	12.6%	12.6%	14.4%	8.3%	9.1%	8.7%
Profit returned to government	66.1%	59.8%	94.7%	69.1%	53.9%	75.4%	68.3%	96.8%
Customers/employee	184	192	203	199	194	175	161	162
Growth in customer base	0.8%	0.3%	0.7%	0.8%	0.5%	0.5%	0.5%	0.3%
GWh sold/employee	7.3	7.3	7.7	7.3	7.0	6.0	5.4	5.4
Self Generation - Cost Structure (3)	(cents per net generated kWh sold) (Tables may not add due to rounding)							
OM&A	1.90	1.73	1.57	1.44	1.35	1.65	1.68	1.68
Fuel	2.11	1.22	1.12	1.03	0.93	0.93	0.93	0.86
Variable costs	4.01	2.94	2.68	2.47	2.28	2.58	2.61	2.53
Gov't levies	0.32	0.31	0.32	0.33	0.34	0.34	0.37	0.33
Net interest expense	0.94	1.01	1.06	1.14	1.29	1.36	1.37	1.33
Total cash costs	5.27	4.27	4.06	3.95	3.91	4.29	4.35	4.19
Non-cash financial charges	0.05	0.04	0.07	0.05	0.04	0.03	0.05	0.03
Depreciation	1.18	1.02	1.03	1.16	1.11	1.09	1.03	1.05
Total costs	6.51	5.33	5.16	5.16	5.06	5.40	5.43	5.27
Purchased power (cts.per gross kWh purch.)	1.87	2.79	2.92	2.15	1.62	1.72	2.02	1.73

(1) Capital expenditures are net customer contributions.

(2) Before capitalized interest/AFUDC. Interest income netted from interest expense.

(3) Internaly generated energy less energy used + lost - excludes purchased power. Transmission losses apportioned relative to total energy supplied.

Saskatchewan Power Corporation

Income Statements	For the years ended Dec. 31 (1993-1997 restated to reflect sale of gas ops.)						
($ millions)	2000	1999	1998	1997	1996	1995	1994
Residential	208.0	207.0	203.0	200.0	202.0	181.0	177.0
Commercial	244.0	236.0	238.0	242.0	238.0	239.0	299.7
Oilfields	106.0	95.0	94.0	90.0	80.0	75.0	191.3
Industrial	243.0	225.0	234.0	203.0	188.0	193.0	
Farm	100.0	100.0	97.0	107.0	104.0	93.0	95.0
Other *	(1.0)	2.0	2.0	3.0	2.0	48.2	54.0
Domestic revenues	900.0	865.0	868.0	845.0	814.0	829.2	817.0
Exports/Reseller	180.0	92.0	72.0	57.0	57.0	7.8	3.8
Total electric revenues	1,080.0	957.0	940.0	902.0	871.0	837.0	820.8
Ancillary businesses	21.0	20.0	13.0	13.0	13.0	10.0	(3.0)
Gas operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total revenues	1,101.0	977.0	953.0	915.0	884.0	847.0	817.8
Expenses:							
Operating, maintenance + admin	264.0	254.0	233.0	213.0	195.0	233.0	224.0
Power purchases	68.8	50.5	44.9	21.1	12.0	5.0	12.0
Fuel costs	294.2	178.5	166.1	151.9	134.0	132.0	124.0
Asset removal/site restoration	14.0	15.0	22.0	41.0	32.0	31.0	25.0
Depreciation + amortization	151.0	135.0	131.0	131.0	128.0	123.0	112.0
Royalties, water rentals + taxes	45.0	46.0	47.0	49.0	49.0	48.0	49.0
Total operating costs	837.0	679.0	644.0	607.0	550.0	572.0	546.0
Operating income	264.0	298.0	309.0	308.0	334.0	275.0	271.8
Interest expense	157.0	173.0	192.0	204.0	216.0	224.0	217.0
Non-cash financial charges	7.0	6.0	11.0	7.0	6.0	4.0	6.0
Other (income)/expense	(26.0)	(24.0)	(34.0)	(35.0)	(30.0)	(31.0)	(34.0)
Net interest expense	138.0	155.0	169.0	176.0	192.0	197.0	189.0
Income before extra. items	126.0	143.0	140.0	132.0	142.0	78.0	82.8
Extraordinary/discontinued items	0.0	29.0	0.0	0.0	3.0	(2.0)	(2.0)
Net income	126.0	114.0	140.0	132.0	139.0	80.0	84.8
		12.3%					
Operating Cash Flow	281.0	256.0	285.0	295.0	291.0	220.0	199.0
LESS: Dividends	68.0	67.0	130.0	76.0	54.0	47.0	41.0
Capital expenditures (net of contrib)	201.0	174.0	125.0	133.0	91.0	157.0	201.0
Cash flow before working capital	12.0	15.0	30.0	86.0	146.0	16.0	(43.0)
LESS: Working capital changes	7.0	(9.0)	2.0	25.0	(2.0)	(8.0)	(7.0)
Free cash flow	5.0	24.0	28.0	61.0	148.0	24.0	(36.0)
LESS: Other investments	0.0	0.0	(1.0)	(19.0)	(1.0)	(2.0)	(2.0)
PLUS: Net financing	18.0	(3.0)	(84.0)	(79.0)	(84.0)	101.0	(159.0)
Net change in cash flows	23.0	21.0	(55.0)	1.0	65.0	127.0	(193.0)
		1.52					
Unit Revenue and Costs	(cents per kWh sold)	(Tables may not add due to rounding)					
Residential	8.90	8.94	8.96	8.53	8.50	7.96	7.98
Commercial	7.16	7.22	7.24	6.91	7.05	7.08	8.91
Oilfields	7.04	7.31	7.57	7.67	7.75	8.21	3.44
Industrial	3.94	3.73	3.72	3.65	3.76	4.00	
Farm	7.66	7.69	7.69	7.25	7.20	6.82	6.74
Other	1.89	14.29	5.88	16.67	0.95	4.23	5.03
Average domestic revenues	6.14	6.08	6.04	6.00	6.06	5.97	5.99
Exports/reseller	7.55	4.61	3.98	3.73	3.51	1.59	2.00
Average electricity revenues	6.33	5.90	5.81	5.78	5.78	5.82	5.94
Ancillary revenues	0.12	0.12	0.08	0.08	0.09	0.07	(0.02)
Net revenues	6.46	6.02	5.89	5.86	5.87	5.89	5.92
Expenses:							
Operating + administration	1.55	1.57	1.44	1.36	1.29	1.62	1.62
Purchased power	0.40	0.31	0.28	0.14	0.08	0.03	0.09
Fuel	1.73	1.10	1.03	0.97	0.89	0.92	0.90
Variable costs	3.68	2.98	2.74	2.47	2.26	2.57	2.60
Gov't levies	0.26	0.28	0.29	0.31	0.33	0.33	0.35
Net interest expense	0.77	0.92	0.98	1.08	1.23	1.34	1.32
Total cash costs	4.71	4.18	4.01	3.87	3.82	4.25	4.28
Cash margin	1.75	1.84	1.88	1.99	2.04	1.64	1.63
Non-cash financial charges	0.04	0.04	0.07	0.04	0.04	0.03	0.04
Depreciation	0.8856824	0.83	0.81	0.84	0.85	0.86	0.81
Site restoration costs	0.08	0.09	0.14	0.26	0.21	0.22	0.18
Pre-tax margin	0.74	0.88	0.86	0.85	0.94	0.54	0.60
Variable costs	3.68	2.98	2.74	2.47	2.26	2.57	2.60
Fixed costs (deprec, int + levies)	2.04	2.16	2.28	2.54	2.66	2.77	2.71
Total costs	5.72	5.14	5.02	5.02	4.93	5.35	5.32

*Prior to 1996, includes sales to resellers.

Saskatchewan Power Corporation

For the years ended December 31

Operating Statistics (millions kWh)								
Electricity Sold - Breakdown		2000	1999	1998	1997	1996	1995	1994
Residential		2,337	2,315	2,266	2,345	2,377	2,273	2,218
Commercial		3,408	3,267	3,288	3,502	3,376	3,374	3,364
Oilfields		1,505	1,299	1,241	1,173	1,032	913	5,564
Industrial		6,164	6,033	6,287	5,565	5,001	4,830	
Farm		1,305	1,300	1,262	1,475	1,444	1,363	1,410
Other *		(53)	14	34	18	210	1,139	1,074
Domestic sales		14,666	14,228	14,378	14,078	13,440	13,892	13,630
Export/reseller		2,383	1,997	1,809	1,530	1,624	491	190
Total sold		17,049	16,225	16,187	15,608	15,064	14,383	13,820
Energy sales growth		5.1%	0.2%	3.7%	3.6%	4.7%	4.1%	0.5%
Generation								
Hydro	30%	853	853	847	847	847	847	847
Coal	57%	1,658	1,658	1,765	1,765	1,765	1,765	1,765
Natural gas	13%	378	378	136	136	136	136	136
Installed capacity - MW		2,889	2,889	2,748	2,748	2,748	2,748	2,748
Total energy generated (millions kWh):								
Hydro		3,046	3,668	3,668	4,005	4,396	4,137	3,395
Coal		12,481	12,622	12,619	12,514	12,184	12,217	12,105
Natural gas		924	995	1,313	910	529	571	502
Gross energy generated	82%	16,451	17,285	17,600	17,429	17,109	16,925	16,002
PLUS: Purchases	18%	3,686	1,811	1,536	982	741	291	595
Energy generated + purchased		20,137	19,096	19,136	18,411	17,850	17,216	16,597
LESS: Transmission losses + internal use		3,088	2,871	2,949	2,803	2,786	2,833	2,777
Total sold		17,049	16,225	16,187	15,608	15,064	14,383	13,820
Energy lost + used/energy gen + purch		15.3%	15.0%	15.4%	15.2%	15.6%	16.5%	16.7%
Maximum primary peak demand		2,822	2,461	2,944	2,944	2,789	2,744	2,616
Peak demand/Installed capacity		97.7%	85.2%	107.1%	107.1%	101.5%	99.9%	95.2%
Export Interconnections (MW)								
Manitoba Hydro		300	300	300	300	300	300	300
Alberta Power		150	150	150	150	150	150	150
United States - Basin Electric		150	150	150	150	150	150	150
Total		600	600	600	600	600	600	600
Interconnections as a % of Installed Capacity		20.8%	20.8%	21.8%	21.8%	21.8%	21.8%	21.8%

* Prior to 1996, includes sales to resellers.

TransAlta Corporation

Current Report: October 25, 2001
Previous Report: October 20, 2000

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RATING

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Downgraded	Unsecured Debentures & Medium Term Notes
Pfd-2 (low)y	Stable	Downgraded	Preferred Securities, cumulative redeemable

RATING HISTORY

	Current	2000	1999	1998	1997	1996
Unsecured Debentures & MTNs	A (low)	"A"	A (high)	NR	NR	NR
Preferred Securities, cumulative redeemable	Pfd-2 (low)y	Pfd-2y	Pfd-2 (high)y	NR	NR	NR

y - denotes hybrid security

RATING UPDATE

DBRS is downgrading the ratings on TransAlta Corporation's ("TransAlta" or "the Company") unsecured debentures and medium-term notes from "A" to A (low), and the rating on its preferred securities from Pfd-2y to Pfd-2 (low)y, all with Stable trends. The downgrade reflects the following considerations. (1) The Company's risk profile will increase considerably in the future given its aggressive expansion program ($1.0 billion to $1.5 billion annually) into non-regulated generation. This will potentially increase earnings volatility, and will pressure the balance sheet and key coverage and cash flow ratios until the projects start generating positive cash flows. (2) The new operating environment in Alberta has proven to be more challenging than expected. In addition to the financial exposure of approximately $90 million relating to the Wabumun unit 4 shutdown (a decision has not yet been rendered in respect of its force majeure claim), the Company is exposed to operating risk for not meeting availability targets set out in the power purchase agreements ("PPAs"). (3) While much of the Company's generation is sold under medium- and long-term contracts, thus mitigating merchant power risk, the Company's small size relative to other North American generators increases the financial impact of an unplanned outage, as evidenced by the outage at Centralia. Its exposure to unplanned outages relative to larger peers will remain higher given the higher average age of its generation assets under PPAs and given that most of its generation assets are coal-based, which tend to be more sensitive to outages than gas-fired plants.

The current rating remains supported by its favourable coverage and cash flow ratios, and management's good track record of performance through the years. In addition, the Company continues to be a low-cost electricity generator, giving it a competitive advantage over its peers.

RATING CONSIDERATIONS

Strengths:

- PPAs provide some degree of earnings and cash flow stability, and higher returns than under previous regime
- Approximately 70% of non-PPA generation subject to medium and long-term sales contracts, with fuel cost flow-throughs
- Low-cost generator
- Favourable interest coverage and cash flow ratios
- Increasing geographic diversification

Challenges:

- Growing exposure to higher risk, non-regulated activities
- Aggressive expansion program
- PPAs increase business risk
- Small size relative to 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. 2001	2000	1999	1998	1997	1996
Fixed-charges coverage (times)		2.94	2.64	2.06	2.70	2.66	2.38
% adj. debt in capital structure (1)		54.8%	52.5%	49.3%	43.2%	41.2%	52.5%
Cash flow/total adj. debt (times) (1)		0.22	0.22	0.19	0.24	0.24	0.22
Cash flow/capital expenditures (times)		0.58	0.77	0.69	1.48	1.50	1.58
Segmented operating income (cont. ops.)							
Regulated/PPAs (TransAlta Utilities)	65%	352.5	266.9	267.9	349.2	437.8	545.5
Non-regulated	35%	189.3	236.6	47.4	59.0	132.0	63.3
Operating income ($ millions)	100%	541.8	503.5	315.3	408.2	569.8	608.8
Net income ($ millions)		(12.0)	279.8	186.4	211.4	182.6	181.0
Operating cash flow ($ millions)		650.6	614.0	471.6	481.9	499.3	494.0
Total electricity sales (millions of kWh)		44,762	41,408	38,177	36,438	36,702	32,510

(1) Preferred securities given 75% equity treatment, perpetual preferred shares 70%. Minority interest treated as common equity.

THE COMPANY

TransAlta Corporation is Canada's largest non-regulated electric generation and marketing company, with more than $7 billion in assets and 8,000 MW of capacity. Its growth is focused on developing coal and gas-fired generation 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.

MARKET ENVIRONMENT - ALBERTA

Bill 27 was passed in April 1998 to amend the Electric Utilities Act to provide a framework for an unbundled, deregulated and competitive market environment effective January 2001. Key features of the legislation and new environment that affect TransAlta are as follows. (1) Cost averaging of existing generation in service at December 1995 will continue under the long-term PPAs, which became effective January 1, 2001 (this impacts TransAlta Utilities Corporation). 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 the owner is adequately compensated for the operating risks. The PPAs also incorporate incentives that encourage operating efficiencies. Deemed equity for the generation assets under the PPAs has been set at 45%. All benefits and risks associated with meeting efficiency targets are borne by the owner of the generation assets. (2) New generation assets (those in service after December 1995) are excluded from the cost averaging process and pricing is market based.

As at September 30, 2001, TransAlta was no longer involved in the electricity retail and distribution business (this business was sold to UtiliCorp Networks Canada (Alberta) Ltd. in August 2000) and had entered into an agreement to sell its electricity transmission assets for Cdn$850 million (the sale is projected to close in Q2 2002). Once the sale of the transmission assets closes, TransAlta will no longer be regulated by the Alberta Energy and Utilities Board.

RATING CONSIDERATIONS

Strengths: (1) PPAs provide a degree of stability to the Company's earnings and cash flows as they allow for the recovery of costs (variable and fixed). They also provide for higher returns compared to the previous regime as they incorporate a 450 bp risk premium above ten-year Government of Canada bonds and the deemed equity component has been raised to 45%. In addition, the PPAs include a framework for the development of performance-based regulation.

(2) About 70% of TransAlta's non-PPA generation, including IPPs, is subject to medium and long-term sales contracts (long-term power contracts for IPPs, two- to seven-year contracts for Centralia), and also includes fuel cost flow-through clauses. This significantly reduces TransAlta's exposure to merchant power risk.

(3) Given the dominance of low-cost coal-based generation and the Company's track record of maintaining low operating and maintenance costs, TransAlta is a low-cost electricity generator, giving it a competitive advantage over its peers.

(4) Despite recent problems with two of its generating assets, its increased risk profile and the increased competition as a result of industry deregulation, the Company has maintained favourable interest coverage and cash flow ratios. The debt to equity ratio should decline to the Company's target ratio of 50% over the medium term, and the fixed-charges coverage should remain near two to three times. While the Company has an aggressive expansion plan, DBRS expects new equity will be issued to keep the balance sheet stable.

(5) The Company is expanding in jurisdictions outside Alberta, which provides for increased geographic diversification and, thus, reduced exposure to price risk and risk of political interference.

Challenges: (1) Given the Company's focus on being a pure electricity generator and its aggressive growth strategy, its risk profile has increased significantly. While the PPAs, which are essentially regulated, currently account for about 60% of TransAlta's recurring net income, this proportion is expected to drop significantly over the next five years. The Company's continued growth in non-regulated activities will increase the volatility of its earnings due to the increased exposure to merchant power risk, energy trading and competitive pressures.

(2) The Company's current growth strategy includes an aggressive expansion program. Given the current economic environment and the reduced demand for electricity, combined with all the new generation planned for North America, the financial risks associated with TransAlta's expansion program have increased dramatically. The expansion program will likely pressure the balance sheet and coverage and cash flow ratios in the short term. It could also result in excess generation supply, which would have a longer term negative impact on its financials.

(3) The PPAs increase TransAlta's business risks. These risks are as follows. (a) There is an 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. (b) Forecast capital expenditures over the life of the PPAs may be below actual requirements. The variance is not recoverable from the PPA holder. (c) Establishing who is at fault and defining *force majeure* in the event of an unplanned shutdown has proven to be difficult, and could result in disputes and litigation if the problem is severe enough.

(4) TransAlta's small size relative to other North American generators increases its risk profile. The financial consequences of an unplanned outage can be significant, as evidenced by the outage at Centralia, as each generator represents a greater proportion of the Company's income stream.

(5) The dominance of coal-based capacity within its generation base could result in increased costs in the future related to environmental concerns. While these increased costs would likely be passed on to the PPA holders for those assets under the PPAs, the competitiveness of the Company's other coal-based assets would likely deteriorate. In addition to the environmental concerns, coal-based generation capacity tends to be more sensitive to outages than other types of generation, thus increasing TransAlta's operating risk profile relative to its peers.

(6) While no longer regulated, the Company continues to face the risk that political bodies (directly or through regulators) will impose restrictions, such as price caps (as experienced in the U.S. and Canada), should market conditions change dramatically.

COMPANY PROFILE

TransAlta Corporation has two principal wholly owned operating subsidiaries.

TransAlta Utilities Corporation, owns and operates the Company's Alberta-based generation assets that are subject to the terms and conditions of long-term Power Purchase Agreements (PPAs). In July 2001, it entered into an agreement to sell its Alberta-based transmission assets for Cdn$850 million to AltaLink, a consortium of companies made up of SNC Lavalin Energy, Trans-Elect Inc., the Ontario Teachers' Pension Plan and Macquarie North America Ltd. (the sale is projected to close in Q2 2002). TransAlta Utilities sold its Alberta distribution and retail businesses to UtiliCorp Networks Canada effective August 2000. Once the sale of the transmission assets closes, TransAlta will no longer be regulated by the Alberta Energy and Utilities Board.

TransAlta Energy Corporation, is engaged in electric and thermal energy supply, energy services and energy marketing in Canada, Australia, U.S. and Mexico. Its primary holdings currently include:

(1) a 50% interest in TransAlta Cogeneration L.P., which owns and operates independent power plants in Ontario, Alberta, and Saskatchewan;
(2) a 100% interest in TransAlta Energy Pty. Ltd., which owns and operates two co-generation plants located in western Australia;
(3) a 1,340-MW coal-fired power plant and mining operation (Centralia) located in Washington State, U.S.; and
(4) ownership interests in a number of independent power projects currently under construction/development including Campeche, Mexico and Sarnia, Ontario

The Company currently has three reporting segments as indicated below:

12 months ended/as at Sept. 30, 2001 ($ millions)	Generation	IPP	Energy marketing	Total
Net revenues	1,689.5	190.0	556.5	2,436.0
EBIT, as reported	269.1	53.2	134.3	456.6
Assets	3,830.8	1,796.2	673.9	6,300.9

EARNINGS

	12 mos. ended	9 months ended		For years ended December 31			
($ millions)	Sept. 2001	Sept. 2001	Sept. 2000	2000	1999	1998	1997
Net revenues	2,614.2	1,959.0	931.8	1,587.0	1,029.4	1,089.9	1,656.4
EBITDA	857.3	539.1	437.3	755.5	525.6	601.3	846.2
EBIT	541.8	328.4	290.1	503.5	315.3	408.2	569.8
Net interest expense	101.7	77.5	77.6	101.8	76.7	96.1	175.6
Net income before extras./disc. ops. (1)	241.2	154.2	118.5	205.5	123.3	164.6	203.1
Net income before pfd div.	11.3	186.0	482.1	307.4	212.7	232.5	203.9
Net income available to common	(12.0)	168.1	459.9	279.8	186.4	211.4	182.6

(1) Discontinued operations include distribution & retail operations for 1998, 1999 and 2000; and transmission operations for June 30, 2000, and 2001.

		12 mos. ended	9 months ended		For years ended December 31		
Segmented EBIT (continuing ops)		Sept. 2001	Sept. 2001	Sept. 2000	2000	1999	1998
Regulated/PPAs (TransAlta Utilities)	65%	352.5	286.8	136.7	266.9	267.9	349.2
Non-regulated	35%	189.3	41.6	153.4	236.6	47.4	59.0
Total		541.8	328.4	290.1	503.5	315.3	408.2
Segmented net income from cont. ops., bef. pfds.							
Regulated/PPAs (TransAlta Utilities)	58%	158.8	175.5	32.1	89.3	86.4	130.3
Non-regulated	42%	113.2	(14.0)	89.7	143.0	46.7	40.2
Total		272.0	161.5	121.8	232.3	133.1	170.5

TransAlta's net income before extraordinary items and discontinued operations (recurring net income) was up a sharp 67% in 2000 due to the earnings contribution of the 1,340 MW Centralia plant (acquired in May 2000) and the improved performance from the energy marketing segment.

The Company's regulated operations (TransAlta Utilities) experienced no growth in 2000 as the reduced production due to the Wabumun unit 4 shutdown offset most of the recovery of the 1999 deferral accounts. The Company's recurring net income continued to post gains for the

12 months ending September 30, 2001, although all the growth came from its regulated assets due to the more favourable environment for generation assets under PPAs (considered regulated by DBRS given the nature of the agreements), which includes higher rates of return plus incentives earned for exceeding availability targets. Energy marketing and IPPs continued to record strong earnings, while the Centralia plant incurred a substantial loss due to unplanned outages, which required TransAlta to purchase power at higher prices than those received under the long-term sales contracts. Furthermore, while the Centralia plant resumed production in June 2001, earnings in the third quarter of 2001 were negatively impacted by losses on a power purchase hedge due to the price cap mechanism imposed by the FERC for the entire WSCC region. The price cap mechanism has also contributed to a reduction in the volatility of electricity prices, which will have a negative effect on the earnings of the energy marketing segment. Earnings from the assets under the PPAs should remain strong for the remainder of 2001. However, the Wabumun unit 4 shutdown could have a negative financial impact on earnings (up to $90 million) if the arbitrators rule against the Company in its *force majeure* claim. While net recurring income for 2001 is expected to be above that recorded in 2000, the growth rate will be much lower.

Outlook: The long-term outlook for EBIT and net income available to common shareholders is generally favourable assuming no further unplanned outages. The generation assets subject to the PPAs should continue to provide the Company with a degree of earnings and cash flow stability, although the earnings contribution from these assets will decline over time as the availability targets decline over the useful lives of the assets and as the terms of the PPAs expire (PPAs for the 4 Wabumun units expire in 2003). Over the longer term, TransAlta's earnings growth will come from its new generation projects and, to a lesser degree, from its ability to exceed the availability targets on its generating units under the PPAs and to sell the excess electricity in the open market. While TransAlta's earnings growth potential is now much higher given its focus on non-regulated activities, the volatility of its earnings has increased given: (1) its small size and the resulting increased financial exposure to unplanned outages; (2) its growing energy marketing and trading segment; and (3) the increasing merchant power risk and competitive pressures from industry deregulation throughout North America.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	12 mos. ended	For years ending Dec. 31			Stress Testing		
Cash flow statement	Sept. 2001	2000	1999	1998	Year 1	Year 2	Year 3
EBITDA	857.3	755.5	525.6	601.3	771.6	771.6	771.6
Net income (after prefs, before extras./disc ops.)	217.9	177.9	97.0	143.5	187.6	152.3	90.0
Depreciation	329.2	321.7	325.5	284.8	286.9	326.6	365.0
Other non-cash adjustments	103.5	114.4	49.1	53.6	0.0	0.0	0.0
Operating cash flow	650.6	614.0	471.6	481.9	474.5	478.9	455.0
Less: common dividends/distributions	185.9	196.8	225.2	171.7	193.9	193.9	193.9
capital expenditures (net of contrib)	1,116.5	795.0	683.0	325.0	1,500.0	1,500.0	1,500.0
Gross free cash flow	(651.8)	(377.8)	(436.6)	(14.8)	(1,219.4)	(1,215.0)	(1,238.9)
Less: working capital changes	95.3	452.2	54.8	11.2	0.0	0.0	0.0
Free cash flow	(747.1)	(830.0)	(491.4)	(26.0)	(1,219.4)	(1,215.0)	(1,238.9)
Less: other inv./acquisitions/disp.	(150.6)	(590.0)	305.8	(187.8)	(850.0)	0.0	0.0
Plus: net debt financing	704.1	386.7	416.9	(282.8)	369.4	1,215.0	1,238.9
Plus: net pfd equity financing	(122.1)	(146.8)	294.8	0.0	0.0	0.0	0.0
Plus: net common equity financing	(31.5)	(21.4)	5.6	214.3	0.0	0.0	0.0
Net change in cash	(46.0)	(21.5)	(79.9)	93.3	0.0	0.0	0.0
Total adjusted debt (1)	2,995.6	2,783.6	2,544.5	2,075.6	3,365.0	4,580.0	5,819.0
% adj. debt in capital structure (1)	54.8%	52.5%	49.3%	44.9%	57.8%	65.4%	71.5%
Fixed-charges coverage (times)	2.94	2.64	2.06	2.70	2.38	1.98	1.39
Cash flow/ total adjusted debt (1)	0.22	0.22	0.19	0.23	0.14	0.10	0.08
Stress test assumptions							
EBITDA growth					-10%	0%	0%
Interest rate					5.9%	5.9%	5.9%

(1) Preferred securities given 75% equity treatment, perpetual preferred shares 70%. Minority interest treated as common equity.

Financial Profile: TransAlta's leverage has increased in recent years, although its fixed charges coverage and key cash flow ratios have improved. The Company has recorded significant free cash flow deficits in recent years as a result of its increased level of capital expenditures. While a significant portion of the free cash flow deficits have been financed with debt, the change in the Company's focus has resulted in a number of asset dispositions, whose proceeds have been used to finance a part of the capital expenditure program. During the nine months ending September 30, 2001, the Company's balance sheet deteriorated as a result of the increased debt issuance required to finance the rising capital expenditures. The share of debt in the capital structure (adjusted for preferred shares and securities) rose to 56.1%, significantly above the Company's target of 50%.

Despite the increased leverage, its key coverage and cash flow ratios remain reasonable.

Outlook: The Company's aggressive capital expenditure and acquisition plan of about $1.5 billion annually over the next five years will have a negative impact on its financial profile due to the increased debt requirements and the lag period between the time the expenditures are made and when they begin generating positive cash flows. Given the current economic environment, the Company may choose to reduce its capital plan, which would reduce the need for debt financing. TransAlta's target capital structure is 50/50 debt/equity, which should help to keep interest coverage and cash flow/debt at reasonable levels in the long term. However, in the medium term, leverage is expected to remain closer to 55% and coverage and cash flow ratios will likely weaken. Given the increasing risk profile of the Company, its interest coverage and cash flow/debt will be more vulnerable to changes in market conditions and, consequently, will be more volatile.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Utility, nor DBRS expectations concerning the future performance of the Utility.

The following scenario has been assumed and analyzed: (1) EBITDA declines 10% in 2001, and remains constant during the following two years; (2) the Company's annual capital expenditures remain at the planned $1.5 billion; and (3) any free cash flow deficit is debt financed (except in 2002, when the deficit is largely financed with the proceeds from the sale of the transmission assets). Under this scenario, the Company could be able to internally fund only about one-third of its capital expenditures over three years. It would likely sharply cut its capital plan or issue new equity to maintain key ratios consistent with its current rating.

Operating Lines of Credit

Credit Facilities	Type
Cdn$1.2 billion	Syndicated bank facility
NZ$298.8 million	Bank credit facility; fully cash collaterized
US$133.6 million	16-year bank credit facility to finance IPP project in Campeche, Mexico
3 Cdn$100 million	Uncommitted revolving credit facility with three banks
US$25 million	Demand line of credit

TransAlta has a Cdn$600 commercial paper program that is fully backed by its syndicated bank facility.

Debt Maturity Schedule (as at September 30, 2001)

	2001	2002	2003	2004	2005	2006 and thereafter
($ millions)	4.9	105.0	355.4	329.3	110.4	1,290.8
% of long-term debt outstanding	0.2	4.8	16.2	15.0	5.0	58.8

(Excludes commercial paper outstanding which the Company intends to maintain beyond 1 year.)

TransAlta Corporation

Balance Sheet
($ millions)

Assets	As at Sept. 2001	As at December 31 2000	1999
Cash + equivalents	61.5	53.8	75.3
Restricted cash	0.0	0.0	88.3
Accounts receivable	1,206.2	1,657.9	394.7
Other	130.6	91.3	56.2
Current assets	1,398.3	1,803.0	614.5
Net fixed assets	5,732.0	5,277.1	4,967.4
Investments	35.7	228.0	247.7
Long-term receivable	306.9	232.9	27.2
Deferred costs	53.9	86.1	75.3
Total	7,526.8	7,627.1	5,932.1

Liabilities & Equity	As at Sept. 2001	As at December 31 2000	1999
Short-term debt	543.0	772.7	214.8
A/P + accr'ds	1,195.0	1,524.1	529.5
L.t.d. due in 1 year	4.2	79.6	211.8
Current liabilities	1,742.2	2,376.4	956.1
Def'd taxes & credits	868.5	804.5	242.0
Long-term debt	2,377.0	1,821.8	1,924.8
Non-recourse debt	0.0	0.0	40.8
Pfd securities	285.6	292.0	287.1
Minority interests	280.6	253.4	377.4
Perpetual pfd shares	0.0	121.6	268.3
Shareholders equity	1,972.9	1,957.4	1,835.6
Total	7,526.8	7,627.1	5,932.1

Ratio Analysis	12 mos.	For years ended December 31						
Liquidity Ratios	Sept. 2001	2000	1999	1998	1997R	1996	1995	1994
Current ratio	0.80	0.76	0.64	0.92	0.55	0.63	0.89	0.86
Accumulated deprec/gross fixed assets	31.1%	32.0%	38.4%	43.4%	38.7%	38.1%	38.7%	39.1%
Cash flow/total debt	0.22	0.23	0.20	0.24	0.22	0.20	0.21	0.20
Cash flow/adjusted total debt (1)	0.22	0.22	0.19	0.23	0.22	0.20	0.20	0.20
Cash flow/capital expenditures	0.58	0.77	0.69	1.48	1.58	1.44	1.25	2.94
Cash flow-dividends/capital exp. (2)	0.42	0.52	0.36	0.95	1.08	0.99	0.82	1.85
% debt in the capital structure	53.5%	50.5%	46.4%	43.2%	52.5%	54.5%	53.3%	55.9%
% adj. debt in the capital structure (1)	54.8%	52.5%	49.3%	44.9%	54.4%	56.3%	55.4%	56.9%
Average coupon on long-term debt	6.66%	7.12%	7.00%	7.90%	-	-	-	-
% hybrids/common equity (1)	12.7%	18.7%	25.1%	11.4%	15.2%	15.5%	16.9%	7.8%
Common dividend payout (bef extras.)	75.9%	94.8%	174.7%	109.3%	86.1%	66.4%	87.9%	74.6%
Coverage Ratios (4)								
EBIT interest coverage	3.79	3.58	2.93	3.58	2.81	3.19	3.09	3.64
EBITDA interest coverage	6.01	5.37	4.80	5.21	4.13	4.64	4.43	5.11
Fixed-charges coverage	2.94	2.64	2.06	2.70	2.38	2.56	2.35	2.53
Earnings Quality/Operating Efficiency								
Operating margin	20.7%	31.7%	30.6%	37.5%	34.4%	39.4%	41.4%	43.4%
Net margin (after pfd)	8.3%	11.2%	9.4%	13.2%	11.0%	15.2%	12.8%	16.5%
Return on avg common equity (3)	-0.54%	12.65%	8.16%	10.27%	10.42%	10.77%	11.61%	14.31%
Approved ROE - TransAlta Utilities	10.29%*	9.25%	9.25%	12.00%	39.57%	11.25%	12.25%	11.88%
Installed Capacity								
TransAlta Utilties (regulated/PPAs)	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
TransAlta Energy (non-regulated)	2,547	2,394	1,464	1,008	832	815	485	485
Total (MW)	7,023	6,870	5,940	5,484	5,308	5,291	4,961	4,961
Electricity sales (reg./PPAs)(millions of kWh)	27,452	28,636	27,560	27,672	28,463	27,844	28,380	27,450
Electricity sales (non-reg.)(millions of kWh)	17,310	12,772	10,617	8,766	8,239	4,666	3,561	2,860

(1) Adjusted for equity treatment of hybrids securities. Pref. securities given 75% equity treatment, perpetual preferred shares 70%.
Minority interest treated as common equity. (2) Distributions to non-controlling subsidiaries treated as dividends.
(3) Minority interest treated as common equity. (4) Before capitalized interest and AFUDC.
D&R business treated as discontinued operations effective 1998. 1997R: Argentina investment treated as discontinued operations.
* Approved ROE for 2001 for assets under the PPAs

Generation assets under PPAs

	Fuel source	Committed Capacity MW*	Target availability for 2001	Target availability for 2002	PPA Term
Keephills (2 units)	Coal	766	89.99%	89.89%	2020
Sheerness (2 units)	Coal	756.2	89.99%	89.89%	2020
Sundance A (2 units)	Coal	560	84.64%	84.55%	2017
Sundance B (2 units)	Coal	706	86.94%	86.85%	2020
Sundance C (2 units)	Coal	710	86.94%	86.85%	2020
Wabamun (4 units)	Coal	547.9	76.38%-86.45%	74.30%-84.36%	2003
Hydros (6 units)	Hydro	393	N/A	N/A	2013-2020
Total		**4,439.1**			

* Capacity which it is committed to provide to the purchaser of the PPA.

Non-Regulated Generation Assets

	Capacity – MW	Ownership	On Stream	% of sales contracted	Fuel supply
Operating					
Centralia, U.S.	1,340	100%	1971-72	70-80% until 2006	Own fuel supply (coal)
Under Construction					
Centralia (new), U.S.	248	100%	2002Q3	Spot	Contract (gas) – to be determined

Independent Power Projects

	Capacity – MW	Ownership	On Stream	% of sales contracted	Fuel supply
Operating					
Ottawa, Ontario	68	50%	1992	100% until 2012	Contract until 2007
Mississauga, Ontario	110	50%	1992	100% until 2017	Contract until 2012
Windsor, Ontario	70	50%	1996	100% until 2016	Contract until 2007
Fort Saskatchewan (Dow), Alberta	120	30%	1999	100% until 2019	Supplied by Dow
Meridian (Lloydminster/SaskPower), Saskatchewan.	215	50%	1999	100% until 2024	Contract until 2024
Poplar Creek (Suncor), Alberta	360	100%	2001	41% to 2024	Spot (55% flow-through)
Binghampton, U.S.	55	100%	1992	0% - peaker	Spot
Southern Cross (Western Mining), Australia	250	85%	1999	100% until 2014	Supplied by Western Mining
Parkeston Plant (Normandy Mining), Australia	110	50%	1999	100% until 2016	Contract until 2016
Total	**950.2***				

Under Construction					
Sarnia, Ontario	650^	100%	1999-2002	Target 70%	Flow-through – contract under negotiation
Pierce, US	154	100%	2001Q3	0% - peaker	Spot
Campeche, Mexico	252	100%	2003Q1	100% for 25 yrs	25-yr contract
Chihuahua, Mexico	259	100%	2003Q2	100% for 25 yrs	17-yr contract
Total	**1,315**				

* TransAlta's proportionate ownership interest. ^ 210 MW currently operational.

TransAlta Utilities Corporation

Current Report: October 25, 2001
Previous Report: October 20, 2000

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RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Downgraded	Secured Debentures*
A (low)	Stable	New Rating	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	2000	1999	1998	1997	1996	1995
Secured Debentures	"A"	A (high)	AA (low)	AA (low)	AA (low)	AA	AA
Unsecured Debentures	A (low)	NR	NR	NR	NR	NR	NR

RATING UPDATE

DBRS is downgrading the rating on the secured debentures of TransAlta Utilities Corporation ("TransAlta Utilities" or "the Utility") from A (high) to "A", and is assigning a rating of A (low) to the Utility's unsecured debentures (there are no unsecured debentures currently outstanding and the Company has stated its intent not to issue any further secured or unsecured debentures from Utility), all with Stable trends. The downgrade is based on the following considerations. (1) The new operating environment in Alberta has proven to be more challenging than expected. In addition to the financial exposure of approximately $90 million relating to the Wabumun unit 4 shutdown (a decision has not yet been rendered in respect of its *force majeure* claim), the Utility is exposed to operating risk of not meeting availability targets set out in the PPAs. The Utility's exposure to unplanned outages relative to its peers will remain higher given the age of its assets and the fact they are all coal-based, which tend to be more sensitive to outages than other types of generators. (2) The Utility lacks diversification across business segments and is small relative to other North American generators. As a result, the financial impact from one unplanned outage is more significant for the Utility than for larger, more diversified utilities. (3) While the Utility currently faces no merchant power risk or competition, the PPAs for its older generation assets (547.9 MW) expire in 2003. Therefore, starting in 2004, the Utility's risk profile will increase as those assets will be subject to competition. The Utility has historically been a low-cost generator, which should provide it with a competitive advantage. The current rating remains supported by the favourable balance sheet and management's track record of good performance through the years. The Utility is concentrating on the more volatile electricity generation business, but has exhibited strong operating results here in the past.

RATING CONSIDERATIONS

Strengths:

- PPAs provide for relative earnings and cash flow stability, plus higher rates of return than under previous regulatory environment
- Strong cash flow generator
- Key debt and coverage ratios compare favourably to its peers

Challenges:

- PPAs increase business risk
- Lack of diversification and small size
- Higher average age of assets
- Earnings sensitive to interest rates through ROE formula
- Risk profile will increase as PPA terms expire and if new Alberta generation projects are set up as part of TransAlta Utilities

FINANCIAL INFORMATION

	12 mos. ended	For the year ending December 31					
	Sept. 2001	2000	1999	1998	1997	1996	1995
Fixed-charges coverage (times)	3.55	2.05	1.92	2.46	2.49	2.99	2.66
% adj. debt in the capital structure (1)	54.0%	60.3%	54.4%	50.8%	52.4%	50.8%	52.4%
Cash flow/total adj. debt (1) (times)	0.20	0.24	0.20	0.24	0.25	0.27	0.24
Cash flow/capital expenditures (times)	1.68	1.89	1.45	2.09	1.96	1.92	2.70
Net income (bef. extras./disc. ops., after pfd)($ mil	201.7	76.5	65.3	109.2	140.9	188.3	175.4
Operating cash flow (after pfd) ($ millions)	370.6	373.7	323.7	348.7	378.5	419.3	415.5
Electricity sales (millions of kWh)	27,453	28,636	27,561	27,672	28,463	27,844	28,380
Variable costs* (cents per net gen kWh sold)	1.29	0.97	1.11	1.13	1.51	1.13	1.51
Fixed costs (cents per net gen kWh sold)	0.93	1.05	1.07	1.06	1.39	1.06	1.39
Avgerage coupon on long-term debt	7.27%	7.21%	7.78%	8.16%	8.78%	9.32%	9.34%

(1) Intercorporate preferred securities given 50% equity treatment, perpetual preferred shares given 70% equity treatment. * Before income taxes

THE COMPANY

TransAlta Utilities Corporation is now 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 medium- and long-term PPAs. The Utility is wholly owned by TransAlta Corporation.

MARKET ENVIRONMENT

Bill 27 was passed in April 1998 to amend the *Electric Utilities Act* to provide a framework for an unbundled, deregulated and competitive market environment effective January 2001. The key feature of the legislation and new environment that affects TransAlta Utilities is that cost averaging of existing generation in service at December 1995 will continue under the long-term PPAs, which became effective January 1, 2001. 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 the owner is adequately compensated for the operating risks. The PPAs also incorporate incentives that encourage operating efficiencies. Deemed equity for the generation assets under the PPAs has been set at 45%. All benefits and risks associated with meeting efficiency targets are borne by the owner of the generation assets.

As at September 30, 2001, TransAlta Utilities was no longer involved in the electricity retail and distribution business (this business was sold to UtiliCorp Networks Canada (Alberta) Ltd. in August 2000) and had entered into an agreement to sell its electricity transmission assets for Cdn$850 million (the sale is projected to close in Q2 2002). Once the sale of the transmission assets closes, TransAlta Utilities will no longer be regulated by the Alberta Energy and Utilities Board.

RATING CONSIDERATIONS

Strengths: (1) PPAs provide a significant degree of stability to the Utility's earnings and cash flows as they allow for the recovery of costs (variable and fixed). They also provide for higher returns as they incorporate a 450 bp risk premium above ten-year Government of Canada bonds and the deemed equity component has been raised to 45%. In addition, the PPAs include a framework for the development of performance-based regulation.

(2) TransAlta Utilities has historically generated operating cash flows well in excess of capital expenditure requirements. Given the higher allowed rate of return on the Utility's assets under PPAs and the financial results for the year-to-date 2001, it is expected that the Utility will continue to generate strong operating cash flows.

(3) Key debt and coverage ratios compare favourably to its peers (other regulated electric utilities). In addition, TransAlta Utilities is the largest electricity generator in Alberta and remains one of the strongest electric utilities in Canada.

Challenges: (1) The PPAs increase the Utility's business risk. These risks are as follows: (a) There is an 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. (b) Forecast capital expenditures over the life of the PPAs may be below actual requirements. The variance is not recoverable from the PPA holder. (c) Establishing who is at fault and defining *force majeure* in the event of an unplanned shutdown has proven to be difficult, and could result in disputes and litigation if the problem is severe enough.

(2) TransAlta's small size relative to other North American generators and its lack of diversification increases its risk profile. The financial consequences of an unplanned outage can be significant, as each generator represents a higher proportion of the Utility's income stream than for larger, more diversified utilities.

(3) Given the age of its assets and the fact they are all coal-based, which tend to be more sensitive to outages than other types of generators, the Utility's exposure to unplanned outages is higher.

(4) Earnings are sensitive to interest rates through the approved ROE formula. The approved ROEs for generation assets under long-term PPAs are set at 450 bps over ten-year Government of Canada bonds. While this is much higher than the approved ROEs for regulated utility operations, the formula remains sensitive to changes in interest rates.

(5) The $1.8 billion, 900 MW expansion to its Keephills coal-fired plant announced by TransAlta Corporation, as well as any other future additions to Alberta generation may be set up as part of TransAlta Utilities. These generating plants will not be subject to the PPAs. If these projects are set up as part of the TransAlta Utilities, the Utility's financial profile could deteriorate depending on the financing structure, while its risk profile would increase.

EARNINGS

	12 mos. ended	9 mos. ended		For years ending December 31				
($ millions)	Sept. 2001	Sept. 2001	Sept. 2000	2000	1999	1998	1997	1996
Revenues	968.5	656.0	429.4	741.9	772.0	853.6	1,128.5	1,196.5
EBITDA	584.8	378.6	225.4	431.6	431.1	506.7	655.7	779.3
EBIT	417.0	286.8	136.7	266.9	267.9	349.2	437.8	545.5
Net interest expense	58.9	17.4	62.4	103.9	97.9	100.3	133.7	131.6
Net income before extras./disc. ops. (1)	232.7	175.5	32.1	89.3	86.4	130.3	162.2	214.2
Net income before pfd div.	22.5	204.5	137.9	(44.1)	108.2	155.2	162.2	214.2
Net income available to common	(8.5)	176.8	128.4	(56.9)	87.1	134.1	140.9	188.3

(1) Discontinued operations include distribution & retail operations for 1998, 1999 and 2000; and transmission operations for June 30, 2000, and 2001.

Since the opening of the competitive market in Alberta on January 1, 2001, the Utility's net income before extraordinary items and discontinued operations ("recurring net income") has increased significantly (it grew by just over five times during the nine months ended September 30, 2001, relative to the same period in 2000) due to the more favourable environment for generation assets under PPAs, which includes higher rates of return plus incentives earned for exceeding availability targets. The increased earnings due to the new PPA environment more than offset the effects of the penalties incurred in the third quarter of 2001 for not meeting the availability targets. No provision has been recorded for the Wabumun unit 4 shutdown from August 2000 to June 2001 as the Utility has claimed *force majeure*. If the arbitrators rule against the Utility in its *force majeure* claim, the financial impact to the Utility's earnings would be approximately $90 million. It should be noted that the *force majeure* claim applies only to the period starting January 1, 2001, when the PPAs came into effect.

TransAlta Utilities' recurring net income was essentially unchanged in 2000 as recovery of the 1999 deferral accounts was largely offset by the reduced production due to the Wabumun unit 4 shutdown. This follows a sharp decline in 1999, which was largely due to an adverse regulatory decision announced in late 1999 that reduced the Utility's approved ROE from 12% for 1998 to 9.25% for 1999.

The discontinuance of regulatory accounting effective January 1, 2001, resulted in a significant extraordinary charge of $209.7 million for the Utility in 2000, which combined with the net income of the discontinued distribution and retail operations of $76.3 million, resulted in reported net loss of $56.9 million for the year.

Outlook: Provided the Utility does not experience further unplanned outages on its generation assets, the outlook for its EBIT and net income available to common shareholders is stable. Earnings should move in line with changes in long-term interest rates given the formula-based ROE targets. Over time, the earnings contribution from the PPAs will decline as the availability targets decline over the useful lives of the assets and as the PPAs expire (the PPAs for 547.9 MW expire in 2003). However, additional earnings will come from the Utility's ability to exceed the availability targets set out in the PPAs, and from non-regulated electricity sales when the PPAs expire.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	12 mos. ended	For years ending December 31			Stress Testing		
Cash Flow Statement	Sept. 2001	2000	1999	1998	Year 1	Year 2	Year 3
EBITDA	584.8	431.6	431.1	506.7	526.3	526.3	526.3
Net income (after prefs., before extras./disc. ops.)	201.7	76.5	65.3	109.2	147.3	144.3	141.2
Depreciation	168.4	218.1	239.7	221.7	160.0	161.2	162.4
Other non-cash adjustments	0.5	79.1	18.7	17.9	0.0	0.0	0.0
Operating Cash Flow	370.6	373.7	323.7	348.8	307.3	305.5	303.6
Less: common dividends	0.0	297.3	169.6	157.0	170.0	170.0	170.0
capital expenditures (net of contrib)	220.8	197.3	223.6	166.8	200.0	200.0	200.0
Gross Free Cash Flow	149.8	(120.9)	(69.5)	25.0	(62.7)	(64.5)	(66.4)
Less: working capital changes	(21.1)	427.3	51.4	57.0	0.0	0.0	0.0
Free Cash Flow	170.9	(548.2)	(120.9)	(32.0)	(62.7)	(64.5)	(66.4)
Less: other investments	1,024.9	(855.7)	15.3	(3.0)	0.0	0.0	0.0
Plus: net debt financing	(23.9)	(50.7)	132.9	29.1	62.7	64.5	66.4
Plus: net pfd equity financing	877.9	(46.8)	0.0	0.0	0.0	0.0	0.0
Plus: net common equity financing	0.0	(210.0)	3.3	0.0	0.0	0.0	0.0
Net change in cash	0.0	0.0	0.0	0.1	(0.0)	0.0	(0.0)
Total adjusted debt (1)	1,865.9	1,531.2	1,609.5	1,477.6	1,928.6	1,993.1	2,059.4
% adj. debt in capital structure (1)	54.0%	60.3%	54.4%	50.8%	55.2%	56.4%	57.7%
Fixed-charges coverage (times)	3.55	2.05	1.92	2.46	3.06	3.37	3.24
Cash flow/ total adjusted debt (1)	0.20	0.24	0.20	0.24	0.16	0.15	0.15
Stress Test Assumptions							
EBITDA growth					-10%	0%	0%
Interest rate					6.2%	6.2%	6.2%

(1) Inter-company preferred securities given 50% equity treatment; perpetual preferred shares given 70% equity treatment.

Financial Profile: TransAlta Utilities' financial profile deteriorated slightly it 1999 and 2000, but has since improved. The Utility has recorded two consecutive years of gross free cash flow deficits, although this is not likely to be the case in 2001 given the strong operating cash flows generated over the 12 months ended September 30, 2001, and the stable level of capital expenditures. The gross free cash flow deficit in 2000 was entirely due to the significantly higher dividend payments to its parent as a result of the sale of its distribution and retail operations. During the nine months ended September 30, 2001, the Utility's balance sheet improved as a result of the substantial reduction in debt combined with the issuance of $1 billion in preferred securities to its parent, which was subsequently used to purchase $1 billion of preferred shares from TransAlta Energy Company, a wholly owned direct subsidiary of TransAlta Corporation. These preferred shares pay a higher dividend rate than the preferred securities issued by the Utility. The Utility's per cent of adjusted debt in its capital structure fell to 54.0% as at September 30, 2001, from 60.3% at the end of 2000. Its fixed-charges coverage also improved significantly to 3.58 times for the twelve months ending September 30, 2001, from 2.05 times in 2000. Part of the improvement in the Utility's balance sheet and in its interest coverage ratios to date could be reversed if the arbitrators rule against the Utility in its force majeure claim relating to its Wabumun Unit 4.

Outlook: Provided the Utility does not experience further unplanned outages on its generation assets, its financial profile should remain relatively stable. As a result of the structure of the PPAs, operating cash flows are expected to remain more than sufficient to cover the Utility's annual capital expenditures of about $200 million over the next three years. It is expected that the Utility's dividend payout policy will be set such that a 55/45 debt/equity structure is maintained. Any debt issuance will be done through its parent and is expected to be done solely to maintain a 55/45 debt/equity structure. The Utility's interest coverage and cash flow/debt should remain strong over the medium term.

The utility's risk profile will increase when the PPAs for 547.9 MW expire in 2003, as this generation will become non-regulated. Furthermore, these plants are older and less reliable. In addition, in February 2001, TransAlta Corporation announced a $1.8 billion, 900 MW expansion to its Keephills coal-fired plant. This increase in capacity will not be subject to the PPAs. If TransAlta Corporation decides to undertake the expansion as part of TransAlta Utilities, the Utility's financial profile could deteriorate depending on the financing structure, while its risk profile will increase further.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various extreme scenarios. The assumptions used in the above are not based on any specific information provided by the Company, nor DBRS expectations concerning the future performance of the Utility.

The following scenario has been assumed and analyzed: (1) EBITDA declines 10% in 2001, and remains constant during the following two years; (2) the Utility's annual capital expenditures remain at $200 million; and (3) any free cash flow deficit is debt financed. Under this scenario, the Utility would face annual free cash flow deficits of about $60 million. Its fixed-charges coverage ratio would deteriorate somewhat, but would remain relatively strong, while its capital structure and cash flow/debt would deteriorate. While DBRS expects that the Utility's dividend pay-out requirement would be adjusted and that it would likely use equity financing to cover a portion of the free cash flow deficit, the fact that its financial profile would not be severely impacted indicates it has sufficient financial flexibility.

Operating Lines of Credit

Short-term financing requirements are largely funded with intercorporate advances and borrowings, and bank debt. As at September 30, 2001, the Utility had operating lines of credit totaling $100 million.

Debt Maturity Schedule (as at September 30, 2001)

	2001	2002	2003	2004	2005	2006 and thereafter
($ millions)	1.1	101.8	352.0	102.2	84.1	543.2
% of total long-term debt	0.1	8.6	29.7	8.6	7.1	45.9

None of the outstanding debentures is redeemable or callable during the next five years. All of the outstanding debentures held publicly ($934.5 million as at September 30, 2001) are secured by a floating charge on the property and assets of the Utility. The Utility's parent, TransAlta Corporation, holds the remaining $250 million in outstanding debentures.

TransAlta Utilities Corporation

Balance Sheet

($ millions)	As at	As at December 31			As at	As at December 31	
Assets	Sept. 2001	2000	1999	**Liabilities & Equity**	Sept. 2001	2000	1999
Cash + equivalents	0.0	0.0	0.0	Short-term debt	144.0	207.9	56.7
Receivables	261.6	264.9	193.7	L.t.d. due in 1 yr	1.1	76.7	209.9
Inventories	53.0	51.5	55.7	Other current liab.	266.4	152.0	297.8
Current assets	314.6	316.4	249.4	Current liabilities	411.5	436.6	564.4
Net fixed assets	2,663.0	2,626.5	3,040.0	Def'd taxes + credits	370.4	349.7	54.0
Def'd charges + other	15.4	15.8	20.0	Long-term debt	1,183.3	1,161.1	1,262.4
Other investments	1,096.1	81.0	0.0	Preferred securities	1,074.9	98.0	0.0
				Perpetual pfd shares	0.0	121.6	268.3
				Shareholders' equity	1,049.0	872.7	1,160.3
Total	4,089.1	3,039.7	3,309.4	Total	4,089.1	3,039.7	3,309.4

Ratio Analysis	12 mos. ended	For years ending December 31						
Liquidity Ratios	Sept. 2001	2000	1999	1998	1997	1996	1995	1994
Current ratio	0.76	0.72	0.44	0.43	0.39	0.46	0.62	0.71
Acc. depreciation/gross fixed assets	47.0%	46.1%	49.0%	47.8%	45.7%	43.9%	41.5%	38.7%
Cash flow/total debt (incl debt equiv)	0.28	0.26	0.21	0.25	0.26	0.28	0.25	0.25
Cash flow/adj. total debt (1)	0.20	0.24	0.20	0.24	0.25	0.27	0.24	0.23
Cash flow/capital expenditures (2)	1.68	1.89	1.45	2.09	1.96	1.92	2.70	2.93
Cash flow-dividends/capital exp. (2)	1.68	0.39	0.69	1.15	0.42	1.06	1.30	1.80
% debt in capital structure (incl debt equiv)	38.5%	57.0%	51.7%	48.1%	49.6%	47.9%	52.9%	50.0%
% adj. debt in capital structure (1)	54.0%	60.3%	54.4%	50.8%	52.4%	50.8%	52.4%	50.5%
Average coupon on long-term debt	7.27%	7.21%	7.78%	8.16%	8.78%	9.32%	9.34%	9.56%
Hybrids/common equity	102.5%	25.2%	23.1%	21.6%	22.4%	20.1%	13.0%	19.2%
Deemed equity (3)	45.0%	40.0%	40.0%					
Common dividend payout (before extras.)	0.0%	388.6%	259.7%	143.8%	210.8%	100.0%	123.4%	91.4%
Coverage Ratios (4)								
EBIT interest coverage	6.59	2.49	2.63	3.35	3.19	4.02	3.75	3.71
EBITDA interest coverage	9.24	4.02	4.22	4.86	4.78	5.74	5.34	5.28
Fixed-charges coverage	3.55	2.05	1.92	2.46	2.49	2.99	2.66	2.49
Earnings Quality/Operating Statistics								
Fuel costs/revenues	13.9%	16.4%	14.4%	13.0%	9.6%	8.9%	9.1%	8.8%
Operating margin	43.1%	36.0%	34.7%	40.9%	38.8%	45.6%	45.6%	45.2%
Net margin (before extras., after pfd.)	20.8%	10.3%	8.5%	12.8%	12.5%	15.7%	15.0%	14.5%
Return on avg equity (before extras.)	21.0%	7.5%	5.4%	9.0%	11.1%	14.1%	12.9%	12.4%
Approved ROE (PPAs only starting in 2001)	10.29%	9.25%	9.25%	12.00%	^	11.25%	12.25%	11.88%
Customers/employee	n/a	n/a	203	195	166	175	173	167
GWh sold/employee	19.2	22.1	15.3	15.1	13.6	14.3	14.7	14.0
Rate base ($ millions)	n.a.	2,553.6	3,279.0	3,266.0	3,329.0	3,362.0	3,440.0	3,313.6
Growth in rate base	n.a.	-22.1%	0.4%	-1.9%	-1.0%	-2.3%	3.8%	-1.5%
Generation								
Hydro	800	800	800	795	795	795	795	795
Coal	3,676	3,676	3,676	3,676	3,676	3,676	3,676	3,676
Installed capacity (MW)	4,476	4,476	4,476	4,471	4,471	4,471	4,471	4,471
Energy generated (GWh)								
Hydro	1,332	1,492	1,968	1,828	1,626	1,754	1,786	1,574
Coal	26,121	26,630	26,749	27,941	28,727	27,844	28,026	27,737
Gross energy generated	27,453	28,122	28,717	29,769	30,353	29,598	29,812	29,311
Plus: net power exchange	0	514	561	534	557	501	680	401
Energy generated + purchased	27,453	28,636	29,278	30,303	30,910	30,099	30,492	29,712
Less: transmission loss/internal use	0	0	1,717	2,631	2,447	2,255	2,112	2,262
Total - GWh sold	27,453	28,636	27,561	27,672	28,463	27,844	28,380	27,450

(1) Intercorporate preferred securities given 50% equity treatment, perpetual preferred shares given 70% equity treatment.

(2) Net of customer contributions. (3) Generation ops - increases to 45% in 2001. (4) Before capitalized interest, AFUDC. '^ Negotiated settlement.

Self Generation - Cost Structure (1)	2000	1999	1998	1997	1996	1995
	For years ending December 31					
	(cents per net generated kWh sold)		(Tables may not add due to rounding)			
OM&A (incl rate adjustments)	0.56	0.72	0.74	1.15	0.97	0.90
Fuel	0.43	0.41	0.41	0.39	0.39	0.38
Variable costs	0.99	1.13	1.15	1.54	1.36	1.28
Government levies	0.11	0.13	0.13	0.16	0.16	0.17
Net interest expense (excl retract. pfd. divid.)	0.38	0.37	0.38	0.49	0.50	0.51
Total cash costs	1.49	1.64	1.66	2.18	2.02	1.96
Capitalized interest/AFUDC	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)
Depreciation	0.59	0.60	0.58	0.78	0.85	0.82
Total costs (excl income taxes)	2.06	2.23	2.22	2.95	2.86	2.77
Income taxes	0.26	0.31	0.44	0.51	0.73	0.68
Purchased power (cents per gross kWh purchased)	0.00	0.00	0.00	0.00	0.00	1.19
Preferred dividends	0.04	0.08	0.08	0.08	0.09	0.12

(1) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

($ millions)	12 mos. ended	9 mos. ended		For years ending December 31				
Income Statement	Sept. 2001	Sept. 2001	Sept. 2000	2000	1999	1998	1997	1996
Generation				560.0	556.3	639.4	662.4	-
Transmission & distribution (1)				181.9	215.7	214.2	457.1	-
Marketing				0.0	0.0	0.0	9.0	-
Total revenues	968.5	656.0	429.4	741.9	772.0	853.6	1,128.5	1,196.5
Expenses								
Operating + administrative	220.4	163.5	144.1	201.0	195.6	181.1	269.8	266.5
Power purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel	134.6	102.2	89.2	121.6	110.9	110.6	108.0	106.1
Depreciation	167.8	91.8	88.7	164.7	163.2	157.5	217.9	233.8
Property + municipal taxes	28.7	11.7	14.8	31.8	34.4	34.4	43.7	44.6
Rate adjustments	0.0	0.0	(44.1)	(44.1)	0.0	20.8	51.3	0.0
Total operating costs	551.5	369.2	292.7	475.0	504.1	504.4	690.7	651.0
Operating income	417.0	286.8	136.7	266.9	267.9	349.2	437.8	545.5
Interest expense	63.3	21.4	65.4	107.3	102.3	104.6	137.3	135.8
Other (income)/expense (1)	0.0	0.0	0.2	0.2	(1.0)	(1.3)	-	-
Non-cash financial charges	(4.4)	(4.0)	(3.2)	(3.6)	(3.4)	(3.0)	(3.6)	(4.2)
Net interest expense	58.9	17.4	62.4	103.9	97.9	100.3	133.7	131.6
Pre-tax income	358.1	269.4	74.3	163.0	170.0	248.9	304.1	413.9
Income taxes	125.4	93.9	42.2	73.7	83.6	118.6	141.9	199.7
Net income before extraordinary	232.7	175.5	32.1	89.3	86.4	130.3	162.2	214.2
Less: extra. items/discont'd ops	210.2	(29.0)	(105.8)	133.4	(21.8)	(24.9)	0.0	0.0
Net income	22.5	204.5	137.9	(44.1)	108.2	155.2	162.2	214.2
Preferred dividends/distributions	31.0	27.7	9.5	12.8	21.1	21.1	21.3	25.9
Net income avail. to common shldrs.	(8.5)	176.8	128.4	(56.9)	87.1	134.1	140.9	188.3

(1) Includes net intercorp income/expense.

Generation assets under PPAs

	Fuel source	Committed Capacity MW*	Target availability for 2001	Target availability for 2002	PPA Term
Keephills (2 units)	Coal	766	89.99%	89.89%	2020
Sheerness (2 units)	Coal	756.2	89.99%	89.89%	2020
Sundance A (2 units)	Coal	560	84.64%	84.55%	2017
Sundance B (2 units)	Coal	706	86.94%	86.85%	2020
Sundance C (2 units)	Coal	710	86.94%	86.85%	2020
Wabamun (4 units)	Coal	547.9	76.38%-86.45%	74.30%-84.36%	2003
Hydros (6 units)	Hydro	393	N/A	N/A	2013-2020
Total		**4,439.1**			

* Capacity which it is committed to provide to the purchaser of the PPA.

UtiliCorp Networks Canada (British Columbia) Ltd.

(Formerly as West Kootenay Power Limited)

Current Report: November 20, 2001
Previous Report: October 20, 2000

RATING

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

RATING HISTORY (as at Dec. 31)	Current	2000	1999	1998	1997	1996	1995
Secured Debentures	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	A (low)

RATING UPDATE

DBRS is confirming the long-term debt rating of UtiliCorp Networks Canada (British Columbia) Ltd. ("UNBC" or "the Company") at BBB (high) with a Stable trend. UNBC recently changed its legal name from West Kootenay Power Limited. The rating confirmation is based on the following factors: (1) the secured debentures are guaranteed by its U.S. parent, UtiliCorp United Inc.; (2) UNBC's stable earnings and cash flows as a regulated utility (approved ROE was 10% in 2000); (3) low-cost electricity generation from its hydroelectric plants; and (4) UNBC serves an attractive service region.

The Company's financial performance continued to improve for the 12 months ended September 30, 2001. The balance sheet strengthened following a $20 million equity issuance in 2001 which was used to reduce outstanding debt, and accordingly, leverage was 57% debt/capital as at September 30, 2001, compared to the historical levels of 59%-62%. Cash flows have historically been stable, but, given UNBC's sizeable capex program to upgrade transmission/distribution facilities, free cash flow deficits resulted. UNBC has financed such deficits to maintain its capital structure near a 60%/40% debt/equity mix.

In March 2001, UNBC announced it agreed to divest its generating assets (four hydroelectric plants, total 205 MW) for $120 million to Columbia Power Corporation, subject to regulatory approval. In November 2001, the British Columbia Utilities Commission approved the sale but with certain restrictions. As a result of the terms imposed, UNBC will not proceed with the sale at this time.

RATING CONSIDERATIONS

Strengths:

- Competitive, low-cost hydroelectric generation base
- Secure, reasonably-priced electricity supply contracts
- Diverse customer mix
- Favourable regulatory environment; Performance Based Regulation (PBR)

Challenges:

- Electric industry restructuring
- Earnings sensitive to interest rates via approved ROE
- Large capital projects planned
- Small size versus government-owned B.C. Hydro

FINANCIAL INFORMATION

	12 months	For years ended December 31					
	Sept. 2001	2000	1999	1998	1997	1996	1995
Fixed-charges coverage (times)	2.19	2.18	2.20	2.22	2.70	2.71	2.47
% debt in the capital structure (incl debt equiv)	57.2%	62.4%	59.1%	61.3%	59.1%	58.9%	57.0%
Cash flow/total debt (times) (incl debt equiv)	0.11	0.10	0.11	0.11	0.13	0.14	0.17
Cash flow/capital expenditures (times)	0.63	0.61	0.56	0.60	0.87	0.85	0.79
Operating income ($ millions)	34.7	34.2	31.0	30.0	33.5	33.5	29.1
Net income ($ millions)	12.5	12.5	12.0	10.9	12.5	12.1	10.7
Operating cash flow ($ millions)	22.3	22.1	19.5	19.4	19.9	20.0	20.3
Electricity sales (millions of kWhs)	2,826	2,717	2,646	2,617	2,628	2,759	2,623
Electric revenues (1) (cents per kWh sold)	4.97	4.96	4.72	4.71	4.67	4.53	4.46
Variable costs (2) (cents per net gen kWh sold)	2.69	2.72	2.60	2.48	2.33	2.26	2.24
Fixed costs (cents per net gen kWh sold)	1.70	1.68	1.67	1.72	1.65	1.57	1.62
Pre-tax margin (1) (cents per kWh sold)	0.32	0.31	0.25	0.28	0.35	0.35	0.33

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

THE COMPANY

UtiliCorp Networks Canada (British Columbia) Ltd. owns and operates four hydro-electric generating plants (205 MW) on the Kootenay River and provides electricity services to about 135,000 customers in the southern interior of British Columbia. UNBC is a wholly owned subsidiary of Kansas City, Missouri-based UtiliCorp United Inc., a large utility involved in electric and natural gas services, electricity generation, energy marketing/trading, and other energy-related services.

Regulation

UtiliCorp Networks Canada (British Columbia) Ltd. is subject to regulation by the British Columbia Utilities Commission ("BCUC"). The BCUC is authorized to set electricity rates, allowed rate of return on deemed common equity ("ROE"), as well as approve construction of new projects. The ROE is linked to the forecast long-term Bank of Canada bond yield. As a regulated utility, the Company's balance sheet leverage and coverage ratios must be maintained with a 60%/40% debt/equity structure. UNBC's electricity rate increases are established each year to achieve an approved ROE. For 2001, the BCUC approved an ROE of 9.75% (which compares to 10.0% in 2000 and 9.5% in 1999).

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 (2000-02). The PBR provides the Company with incentives for improving operating efficiencies with 50%/50% sharing of savings between UNBC 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 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 40% of UNBC's total electrical load) to choose an alternative electricity supplier. This ruling has not had a material impact to date.

Considerations

Strengths: (1) Low-cost hydroelectric generation provides UNBC with competitive electricity rates. The Company has a lucrative agreement with the government-owned British Columbia Hydro & Power Authority ("BC Hydro"), which constructed dams on waterways feeding UNBC's generating facilities, and allows the Company the right to specified water flows. Therefore, the Company's earnings are not weather-sensitive (i.e., do not fluctuate with water levels) unlike other hydro-based utilities, UNBC's earnings are relatively stable.

(2) UNBC benefits from secure, reasonably priced electricity supply contracts including: (a) a long-term "take-or-pay" contract with Brilliant Power Funding Corporation, which is rated A (high) (see report dated August 31, 2001). The contract runs until 2055 and supplies low-cost power representing about 25% of UNBC's demand load. (b) purchase power contract with the government-owned BC Hydro, which is rated AA(low), based on the Province of British Columbia's guarantee (refer to BC Hydro report dated September 5, 2001). This contract has flexible volumes and is renewed annually.

(3) UNBC generated about 49% of its power requirements and purchased the remaining 51% from power purchase contracts. This diverse power supply mix provides the Company with the flexibility to respond to changes in demand load. Accordingly, the Company is able to reduce power purchases from its most expensive source first.

(4) The Company has a diverse customer mix resulting in stable revenues. Sales to stable residential customers accounted for about half of the total, whereas only 10% of sales were to low-margin, cyclical industrial customers. This helps mitigate any negative impact from a downturn in the economy.

(5) UNBC operates in a favourable regulatory environment. Moreover, the Company benefits from a unique PBR agreement which provides it with incentives for achieving productivity improvements.

(6) The Company's secured debentures and promissory notes are guaranteed by the parent, UtiliCorp United Inc., a large energy company in the U.S. This guarantee provides strong explicit support from a much larger entity.

Challenges: (1) As of March 2000, about 40% of the Company's total load has been subject to open competition. Ongoing electricity industry restructuring (which is already underway in Alberta and Ontario) will lead to increasing competition.

(2) The Company's financial performance is interest rate sensitive, given that earnings are subject to an authorized ROE, which is linked to the long-term Bank of Canada bond yield. The allowed ROE for 2001 fell to 9.75% from the 10% authorized in 2000 (and compares to 9.5% in 1999 and 10.25% in 1998).

(3) The Company has a significant capex program in place over the near term, primarily consisting of: (a) transmission network upgrade estimated to cost $107 million; and (b) hydroelectric plant upgrade costing $100 million to extend the life. Historically, operating cash flows have not been sufficient to fund capex, resulting in free cash flow deficits. This has led to some deterioration of leverage and financial coverage ratios.

(4) UNBC is a small utility compared to its main competitor, the crown corporation BC Hydro and serves a rural and low-population density region. This limits to some extent opportunities for growth, operating efficiencies, and economies of scale. The government-owned BC Hydro is also exempt from paying income taxes.

EARNINGS

($ millions)	12 months ended Sept. 2001	Six months ended Sept. 2001	Six months ended Sept. 2000	For years ending December 31 2000	1999	1998
Revenues	143.926	102.918	97.842	138.850	130.414	126.856
EBITDA	46.449	33.254	30.926	44.121	40.922	40.703
EBIT	34.713	23.952	23.486	34.247	31.046	29.964
Net interest expense	16.000	11.774	11.465	15.691	14.141	13.536
Net income	12.475	9.668	9.656	12.463	12.025	10.866

For fiscal 2000, the Company's net income was up 3.6% to nearly $12.5 million over the previous year's $12 million. The positive earnings contributors are as follows. (1) The Company had continued good growth in electricity sales volumes, which increased by 2.7% to 2,717 million kWh in 2000 compared to a 1.1% improvement in 1999 (corresponding prior year sales were 2,646 million kWh). (2) Total revenues grew 6.5%, primarily as a result of the approved 4.9% increase in electricity rates that took effect on January 1, 2000 (compared to a small 0.64% increase on January 1, 1999). The largest growth in revenues was experienced in the residential sector, which grew 7.4% year over year, while commercial and industrial revenues rose 2.3% and 3.5%, respectively. Wholesale revenues (albeit lower-margin) were up 15.5% and accounted for 57% of the $8.4 million increase in total revenues. (3) The regulator-approved return on deemed common equity (ROE) was set at 10% in 2000, up slightly from 9.5% approved in 1999. Both EBIT and EBIT margins continued their three-year improving trend. The Company benefits from its unique PBR agreement, whereby costs increase with inflation less a productivity factor. This provides the Company with incentives for achieving productivity improvements.

The following factors offset the above positive factors to fiscal 2000 earnings. (1) Power purchase costs rose 11% above 1999, a continuing trend reflective of higher market and contract power costs. In the summer and winter of 2000, UNBC suffered from unexpectedly high prices in the wholesale spot market for electricity. (2) Higher interest expenses reflective of additional long-term debt mainly incurred to finance the Company's significant capital spending projects. Interest costs for 2000 rose by $1.5 million, up 11% over the level in 1999.

For the latest 12-month period ended September 30, 2001, the Company reported stable and improving operating results, which were attributed to: (1) a 5.8% year-to-date increase in electricity sales volumes which rose to 1,978 million kWh for the period; combined with (2) higher revenues (especially to residential and industrial customers up 11% and 13%, respectively) led by a 5% electricity rate increase (that was effective January 1, 2001); and (3) lower operating expenses. However, power purchase costs continued to rise. Earnings were up in spite of the lower approved ROE of 9.75% that was effective January 1, 2001, down from the 10.00% in 2000 (note, ROE reflects the current interest rate environment).

Outlook: Given the regulated nature of the Company's operations, earnings should continue to be fairly stable and the outlook is acceptable. Earnings are determined by the Company's capital structure and an approved return on equity (ROE) linked to the prevailing interest rate environment, and varies from year-to-year. The Company's earnings in the short term may decline modestly given currently lower interest rates. However, future earnings should rise with a larger rate base following completion of the upgrades and life extension work planned particularly on its transmission/distribution facilities.

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

($ millions)	Actual					Stress Testing		
	12 months	For years ended December 31						
Cash flow statement	Sept. 2001	2000	1999	1998	1997	Year 1	Year 2	Year 3
EBITDA	46.4	44.1	40.9	40.7	0.0	37	44	41
Net income (before extras.)	12.5	12.5	12.0	10.9	0.0	5	8	7
Depreciation & amortization	12.3	9.9	9.5	10.6	11.2	12	13	16
Other non-cash adjustments	(2.5)	(0.3)	(2.0)	(2.1)	8.7	0	0	0
Operating cash flow	22.3	22.1	19.5	19.4	19.9	17	22	22
Less: common dividends	6.8	6.8	6.8	6.8	6.8	7	7	7
Less: capital expenditures	35.6	36.5	35.1	32.3	22.8	50	90	110
Gross free cash flow	(20.1)	(21.2)	(22.4)	(19.7)	(9.8)	(40)	(75)	(95)
Less: working capital changes	8.0	14.3	(8.3)	2.4	0.6	0	0	0
Free cash flow	(28.1)	(35.4)	(14.0)	(22.1)	(10.4)	(40)	(75)	(95)
Less: other investments	1.7	0.7	2.9	(1.7)	0.2	0	0	0
Plus: net financing	29.7	36.0	17.0	20.9	10.5	40	75	95
Net change in cash	(0.1)	(0.1)	0.0	0.4	(0.1)	0	0	0
% debt in capital structure (1)	57.2%	62.4%	59.1%	61.3%	59.1%	61.8%	68.9%	68.9%
EBIT interest coverage (times)	2.15	2.18	2.19	2.21	(0.95)	1.47	1.73	1.70
Cash flow/ Total debt (1)	0.11	0.10	0.11	0.11	(0.17)	0.07	0.07	0.08
(1) Cash flows include dividends received, debt is net of sinking fund assets.								
Stress Test Assumptions								
EBITDA growth						-20%	0%	0%
Interest rate (based on three-year average rate)						8.5%	8.5%	8.5%

Operating cash flows for the first half of 2001 and fiscal 2000 remained stable given the Company's regulated operations. However, gross free cash flow (i.e., cash flow after capex, dividends, and changes in working capital) was negative mainly due to large capital spending. The planned upgrades and extensions have resulted in increased leverage and impacted financial ratios at FYE 2000. However, in January 2001, UNBC issued additional common equity and proceeds of $20 million were used to reduce existing term bank loans. This allowed the Company to maintain an appropriate capital structure as leverage fell to 55.7% at June 30, 2001 from 61.3% at December 31, 2000.

Outlook: While cash flows have been stable, DBRS expects free cash flow will likely remain negative in the near term, given the significant investments planned, which will likely be financed near a 60%/40% debt/equity mix. Major projects include: (1) upgrading/rebuilding the transmission network in the Lower Columbia Valley to cost $110 million; (2) South Okanagan transmission upgrade for $70 million (required by 2004); and (3) upgrading of its four generation facilities at an estimated cost of $125 million to $150 million over ten years (which will not be required if generation is divested). Higher debt levels may add pressure on the financial coverage ratios. DBRS expects the Company to maintain an appropriate capital structure (including additional issuances of equity). Note that proceeds from the proposed sale of its generating assets would strengthen the Company's balance sheet.

Sensitivity Analysis:

DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various adverse scenarios. The assumptions used in this stress test are not based upon any information provided by the company, or DBRS expectations. **Assumptions:** EBITDA is decreased by 20% in Year 1 and held flat thereafter, capital expenditures are estimated by DBRS, based on information provided by the Company; there are no proceeds from asset sales, common dividends are maintained, and cash flow deficits in Years 1-3 are entirely debt financed.

Under the above assumptions, the Company is able to finance only a small proportion of capex over three years, resulting in increased debt, and financial ratios would decline sharply under the above assumptions. If these conditions prevail, new equity and cuts in capital expenditures would be anticipated.

OPERATING LINES OF CREDIT

At September 30, 2001, the Company had authorized a $20 million revolving bank line, guaranteed by UtiliCorp United Inc., parent. In addition, the Company has a $40 million demand line facility.

DEBT MATURITY SCHEDULE (As of December 31, 2000)	2001	2002	2003	2004	2005
Long-term debt and sinking fund payments ($ millions)	1.113	1.148	1.186	51.230	1.284

UtiliCorp Networks Canada (British Columbia) Ltd.

(formerly West Kootenay Power Limited)

Balance Sheet
($ millions)

Assets	Sept. 2001	As at December 31 2000	1999	**Liabilities & Equity**	Sept. 2001	As at December 31 2000	1999
Cash + equivalents	0.5	0.5	0.5	Short-term debt	0.0	0.0	0.0
Accounts receivable/unbilled revenue	24.1	24.8	20.0	Debt due 1 yr	0.0	0.0	0.0
Inventories	0.7	0.6	0.5	A/P + accr'ds	18.9	18.4	27.7
Other	3.2	0.5	0.5	Current liabilities	18.9	18.4	27.7
Current assets	28.5	26.4	21.5	Long-term debt	204.6	212.8	176.8
Net fixed assets	340.8	326.0	299.1	Deferred taxes	7.7	7.8	8.1
Deferred charges	14.8	14.9	14.6	Shareholders equity	152.8	128.3	122.6
Total	384.0	367.3	335.2	Total	384.0	367.3	335.2

Ratio Analysis	12 months	For years ended December 31						
Liquidity Ratios	Sept. 2001	2000	1999	1998	1997	1996	1995	1994
Current ratio	1.51	1.44	0.78	1.10	0.98	0.61	0.71	1.10
Accumulated depreciation/gross fixed assets	29.0%	29.2%	29.8%	30.0%	30.4%	29.6%	28.9%	28.7%
Cash flow/total debt (incl debt equiv)	0.11	0.10	0.11	0.11	0.13	0.14	0.17	0.20
Cash flow/capital expenditures	0.63	0.61	0.56	0.60	0.87	0.85	0.79	0.93
Cash flow-dividends/capital expenditures	0.43	0.42	0.36	0.39	0.57	0.56	0.54	0.72
% debt in capital structure (incl debt equiv)	57.2%	62.4%	59.1%	61.3%	59.1%	58.9%	57.0%	58.4%
Average coupon on long-term debt	7.56%	7.96%	8.18%	8.85%	8.76%	9.26%	9.50%	10.50%
Common equity in capital structure	42.8%	37.6%	40.9%	38.7%	40.9%	41.1%	43.0%	41.6%
Deemed common equity (incl def taxes)	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	35.0%	38.0%
Common dividend payout	54.6%	54.6%	56.6%	62.6%	54.2%	56.5%	60.6%	63.2%
Coverage Ratios (1)								
EBIT interest coverage	2.19	2.18	2.20	2.22	2.70	2.72	2.48	2.05
EBITDA interest coverage	2.92	2.81	2.90	3.02	3.63	3.58	3.30	2.77
Fixed-charges coverage	2.19	2.18	2.20	2.22	2.70	2.71	2.47	2.04
Earnings Quality / Operating Efficiency								
Power purchases/revenues	36.2%	34.3%	32.9%	31.6%	28.8%	29.1%	28.3%	30.9%
Operating margin	24.1%	24.7%	23.8%	23.6%	26.6%	26.3%	24.4%	20.3%
Net margin (after pfd divs)	8.7%	9.0%	9.2%	8.6%	10.0%	9.5%	9.0%	8.0%
Return on avg common equity (before extras.)	8.9%	9.9%	10.5%	10.3%	12.5%	12.7%	11.9%	10.1%
Allowed ROE - mid point	9.75%	10.00%	9.50%	10.25%	10.50%	11.25%	12.25%	11.00%
Customers/employee	217	213	223	228	228	215	208	197
Growth of customer base	1.6%	1.3%	1.3%	1.7%	2.0%	2.2%	2.2%	3.4%
GWh sold/employee	-	6.6	6.8	7.0	7.1	7.2	6.7	6.5
Rate base (millions)	$330.9	$318.2	$279.6	$263.0	$243.0	$231.0	$212.4	$191.7
Growth in rate base	4.0%	13.8%	6.3%	8.2%	5.2%	8.8%	10.8%	8.8%
Generation								
Hydro capacity (MW)		205	205	205	205	205	205	205
Gross energy generated (GWh) 49%		1,489	1,494	1,507	1,549	1,425	1,545	1,565
Plus: purchases 51%		1,538	1,468	1,414	1,414	1,685	1,443	1,419
Energy generated + purchased		3,027	2,962	2,921	2,963	3,110	2,988	2,984
Less: transmission losses + internal use		310	316	304	335	351	365	373
Total GWh sold		2,717	2,646	2,617	2,628	2,759	2,623	2,611
Energy lost + used /Energy gen + purch		10.2%	10.7%	10.4%	11.3%	11.3%	12.2%	12.5%
Self-Generation - Cost Structure (2)		(cents per net generated kWh sold)	(Tables may not add due to rounding)					
Variable costs - OM&A		1.96	1.93	1.84	1.81	2.01	1.85	1.87
Government levies		1.56	1.56	1.58	1.44	1.65	1.59	1.47
Net interest expense (excl. retract pfd divid.)		1.17	1.05	0.99	0.89	0.97	0.84	0.78
Total cash costs		4.69	4.54	4.41	4.14	4.62	4.28	4.13
Capitalized interest/AFUDC		(0.04)	(0.03)	(0.03)	(0.02)	(0.03)	(0.01)	(0.03)
Depreciation		0.74	0.74	0.80	0.84	0.84	0.72	0.58
Total costs* (excl income taxes)		5.39	5.25	5.18	4.96	5.43	4.98	4.68
Income taxes		0.50	0.40	0.45	0.66	0.76	0.53	0.24
Purchased power (cents per gross kWh purchased)		3.10	2.92	2.83	2.57	2.20	2.34	2.40
Preferred dividends (cents per net gen kWh sold)		0.00	0.00	0.00	0.00	0.00	0.00	0.00

(1) Before capitalized interest/AFUDC.

* Includes transmission/distribution costs associated with the sale of purchased power.

(2) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

UtiliCorp Networks Canada (British Columbia) Ltd.

(formerly West Kootenay Power Limited)

Income Statements

($ millions)	12 months ended Sept. 2001	Nine months ended Sept. 2001	Nine months ended Sept. 2000	For years ending December 31 2000	1999	1998	1997	1996	1995
Energy - Residential	61.344	46.170	41.419	56.593	52.706	51.982	50.742	52.687	48.080
- Commercial	31.101	22.023	20.861	29.939	29.265	29.781	28.584	29.085	26.260
- Industrial	13.258	9.907	8.756	12.107	11.700	11.912	11.866	12.766	12.783
- Wholesale	34.737	21.417	22.774	36.094	31.252	29.663	31.569	30.309	29.932
Gross electricity revenues	140.440	99.517	93.810	134.733	124.923	123.338	122.761	124.847	117.055
Ancillary revenues	3.486	3.401	4.032	4.117	5.491	3.518	3.281	2.494	2.180
Total revenues	143.926	102.918	97.842	138.850	130.414	126.856	126.042	127.341	119.235
Expenses:		5.2%		8.44					
Power purchases	52.126	36.427	31.960	47.659	42.919	40.060	36.345	37.059	33.767
Operating expenses	23.929	19.753	22.059	26.235	25.775	24.802	24.804	25.403	25.088
Depreciation	11.736	9.302	7.440	9.874	9.876	10.739	11.587	10.586	9.751
Gov't levies + taxes	21.422	13.484	12.897	20.835	20.798	21.291	19.779	20.807	21.507
Total operating costs	109.213	78.966	74.356	104.603	99.368	96.892	92.515	93.855	90.113
Operating income	34.713	23.952	23.486	34.247	31.046	29.964	33.527	33.486	29.122
Interest expense	16.000	11.774	11.465	15.691	14.141	13.536	12.500	12.343	11.965
Non-cash financial charges	(0.749)	(0.537)	(0.378)	(0.590)	(0.435)	(0.342)	(0.300)	(0.421)	(0.150)
Other (income)/expense	(0.250)	(3.278)	(3.060)	(0.032)	(0.079)	(0.115)	(0.232)	(0.101)	(0.564)
Net interest expense	15.001	7.959	8.027	15.069	13.627	13.079	11.968	11.821	11.251
Pre-tax income	19.712	15.993	15.459	19.178	17.419	16.885	21.559	21.665	17.871
Income taxes	7.237	6.325	5.803	6.715	5.394	6.019	9.011	9.585	7.133
Net income bef preferred dividends	12.475	9.668	9.656	12.463	12.025	10.866	12.548	12.080	10.738
Preferred dividends	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.035	0.035
Net income available to common shldrs	12.475	9.668	9.656	12.463	12.025	10.866	12.548	12.045	10.703

Cash Flow Statement

($ millions)	12 months ended Sept. 2001	Nine months ended Sept. 2001	Nine months ended Sept. 2000	For years ending December 31 2000	1999	1998	1997	1996	1995
Net income (after pfd)	12.475	9.668	9.656	12.463	12.025	10.866	12.548	12.045	10.703
Depreciation	12.301	9.866	7.443	9.878	9.497	10.646	11.185	10.796	9.194
Other non-cash adjustments	(2.497)	(2.406)	(0.187)	(0.278)	(1.988)	(2.143)	(3.881)	(2.805)	0.384
Operating cash flow	22.279	17.128	16.912	22.063	19.534	19.369	19.852	20.036	20.281
Less: common dividends	6.812	5.111	5.105	6.806	6.806	6.804	6.804	6.769	6.489
Less: capital expenditures	35.589	19.972	20.836	36.453	35.118	32.312	22.825	23.492	25.572
Gross free cash flow	(20.122)	(7.955)	(9.029)	(21.196)	(22.390)	(19.747)	(9.777)	(10.225)	(11.780)
Less: working capital changes	7.957	1.620	7.913	14.250	(8.349)	2.361	0.618	5.670	(15.761)
Free cash flow	(28.079)	(9.575)	(16.942)	(35.446)	(14.041)	(22.108)	(10.395)	(15.895)	3.981
Less: other investments	1.714	2.175	1.111	0.650	2.878	(1.668)	0.181	0.271	2.318
Plus: net financing	29.697	11.732	18.045	36.010	16.950	20.878	10.501	19.524	0.419
Net change in cash	(0.096)	(0.018)	(0.008)	(0.086)	0.031	0.438	(0.075)	3.358	2.082

Electricity Sold - Breakdown

	Sept. 2001 (12 mo.)	Sept. 2001 (9 mo.)	Sept. 2000 (9 mo.)	2000	1999	1998	1997	1996	1995
Residential	1,080	774	679	985	947	938	940	1,004	959
Commercial	519	391	384	512	543	543	507	518	515
Industrial	346	253	197	290	272	263	289	313	320
Wholesale	881	560	609	930	884	873	892	924	829
Total - GWh sold	2,826	1,978	1,869	2,717	2,646	2,617	2,628	2,759	2,623

Average Unit Revenues and Costs (cents per kWh sold) (Tables may not add due to rounding)

	Sept. 2001 (12 mo.)	Sept. 2001 (9 mo.)	Sept. 2000 (9 mo.)	2000	1999	1998	1997	1996	1995
Revenues:									
Residential	5.68	5.97	6.10	5.75	5.57	5.54	5.40	5.25	5.01
Commercial	5.99	5.63	5.43	5.85	5.39	5.48	5.64	5.61	5.10
Industrial	3.83	3.92	4.44	4.17	4.30	4.53	4.11	4.08	3.99
Wholesale	3.94	3.82	3.74	3.88	3.54	3.40	3.54	3.28	3.61
Average electricity revenues	4.97	5.03	5.02	4.96	4.72	4.71	4.67	4.53	4.46
Ancillary revenues	0.12	0.17	0.22	0.15	0.21	0.13	0.12	0.09	0.08
Net revenues	5.09	5.20	5.23	5.11	4.93	4.85	4.80	4.62	4.55
Costs:									
Operating & administration	0.85	1.00	1.18	0.97	0.97	0.95	0.94	0.92	0.96
Power purchases	1.84	1.84	1.71	1.75	1.62	1.53	1.38	1.34	1.29
Variable costs	2.69	2.84	2.89	2.72	2.60	2.48	2.33	2.26	2.24
Governement levies	0.76	0.68	0.69	0.77	0.79	0.81	0.75	0.75	0.82
Net interest costs (excl. retr. pfd divid.)	0.56	0.43	0.45	0.58	0.53	0.51	0.47	0.44	0.43
Total cash costs	4.01	3.95	4.03	4.06	3.91	3.80	3.55	3.46	3.50
Cash margin	1.09	1.25	1.20	1.05	1.02	1.04	1.25	1.15	1.05
Non-cash financial charges	(0.03)	(0.03)	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)	(0.02)	(0.01)
Depreciation	0.42	0.47	0.40	0.36	0.37	0.41	0.44	0.38	0.37
Pre-tax margin	0.70	0.81	0.83	0.71	0.66	0.65	0.82	0.79	0.68
Income taxes	0.26	0.32	0.31	0.25	0.20	0.23	0.34	0.35	0.27
Net margin	0.44	0.49	0.52	0.46	0.45	0.42	0.48	0.44	0.41
Variable costs (excl income taxes)	2.69	2.84	2.89	2.72	2.60	2.48	2.33	2.26	2.24
Fixed costs (deprec., interest, levies)	1.70	1.55	1.52	1.68	1.67	1.72	1.65	1.57	1.62
Total costs (excl. income taxes)	4.40	4.39	4.41	4.40	4.27	4.20	3.98	3.83	3.86