Q: Reference: Table, Page 15.

Please provide source documents for the table on page 15.

A: The requested source documents are attached.

Re-visiting these documents indicates that a number of corrections and qualifications need to be made to the table on page 15 of Dr. Cannon's evidence, as set out below.

- The value for Gaz Metro for its fiscal 2006 year should be 54.5% (instead of 50.4%)

- The value for Enbridge Gas is the value for calendar year 2005; Dr. Cannon could not find a corresponding value for 2006 in the public record.

- The value for FortisBC refers to electricity sales *revenues* and not volumes.

- The value for FortisAlberta refers to *revenue requirement by customer class* and not volumes.

- The value for Union Gas is the value for calendar year 2004; Dr. Cannon could not find a corresponding value for either 2005 or 2006 in the public record.

For his estimate of NP's industrial sales volumes, Dr. Cannon relied on the Company's evidence in the "Customer, Energy and Demand Forecast" section of its Application, in Volume 2, Tab 8, page 1 and Appendix B.

ATCO Ltd.

2006
ANNUAL
INFORMATION
FORM

February 21, 2007

Utilities

As a result of the Transfer of the Retail Energy Supply Businesses to DEML in May 2004, ATCO Electric and ATCO Gas are no longer involved in arranging for the supply and sale of electricity and natural gas to customers and are therefore no longer responsible for electric energy or natural gas supply, but will continue to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return.

Natural Gas Distribution

ATCO Gas is primarily engaged in the business of distributing natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. Although ATCO Gas is the major natural gas distributor in Alberta, certain areas are served by other natural gas utilities.

ATCO Gas' principal markets for the distribution of natural gas are in the communities of Edmonton, Calgary, Airdrie, Camrose, Fort McMurray, Grande Prairie, Lethbridge, Lloydminster, Red Deer, St. Albert and Sherwood Park, which have a combined population of approximately 2,194,000. Also served are 279 smaller communities as well as rural areas having a combined population of approximately 564,000, located on or in the vicinity of ATCO Pipelines' transportation systems or the natural gas transportation pipelines of other companies. ATCO Gas provides approximately 970,000 customers with natural gas service, of whom approximately 75% are located in the 11 communities named above.

The number of customers served by ATCO Gas as at the end of each of the last two years was as follows:

	2006	2005
Residential	886,999	858,618
Commercial	82,490	80,630
Industrial	358	350
Other	30	-
Total	969,877	939,598

ATCO Gas owns and operates approximately 35,900 km of distribution mains. In addition, ATCO Gas owns modern service and maintenance facilities in major centres.

Revenues and earnings of ATCO Gas are affected by temperature and consequently winter weather can have a significant impact. During a typical year, more than 90% of the earnings of ATCO Gas are generated during the months of January, February, November and December.

The amounts of natural gas distributed by ATCO Gas for each of the last two years were as follows:

	2006	2005
	(petajoules)	
Residential	105.3	103.8
Commercial	98.6	96.9
Industrial	14.4	14.4
Other	0.4	0.4
Total	218.7	215.5

Natural Gas Supply

Prior to April 1, 2005, as directed by the AEUB, ATCO Gas purchased fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. Effective April 1, 2005, as directed by the AEUB, ATCO Gas no longer purchases fixed quantities of natural gas related to storage purchases and operational contracts pertaining to its natural gas field storage facility at Carbon, Alberta. ATCO Gas has leased

Electric Distribution and Transmission

ATCO Electric is engaged in the business of transmitting and distributing electric energy to 245 communities as well as rural areas in east-central and northern Alberta. Included are the communities of Drumheller, Lloydminster, Grande Prairie and Fort McMurray as well as the oil sands areas near Fort McMurray and the heavy oil areas near Cold Lake and Peace River. Electric utility service is also provided to one community in British Columbia and to two communities in Saskatchewan. YECL serves 19 communities in the Yukon Territory, including the capital city of Whitehorse, and NUY and NLD serve 9 communities in the Northwest Territories, including the capital city of Yellowknife.

Electricity distributed to the various classes of customers for each of the last two years was as follows:

	2006		2005	
	Millions of Kilowatt Hours	%	Millions of Kilowatt Hours	%
Industrial	6,719	65	6,583	66
Commercial	1,967	19	1,826	19
Residential	1,098	11	1,023	10
Rural, REAs and other	502	5	494	5
Total	10,286	100	9,926	100

The aggregate population of the areas provided with electric utility service by ATCO Electric, NUY, NLD and YECL is approximately 465,000 and service is provided to approximately 216,000 customers. ATCO Electric has been assigned approximately 65% of the designated service area within Alberta which contains approximately 15% of the existing provincial electrical load and 13% of the existing population.

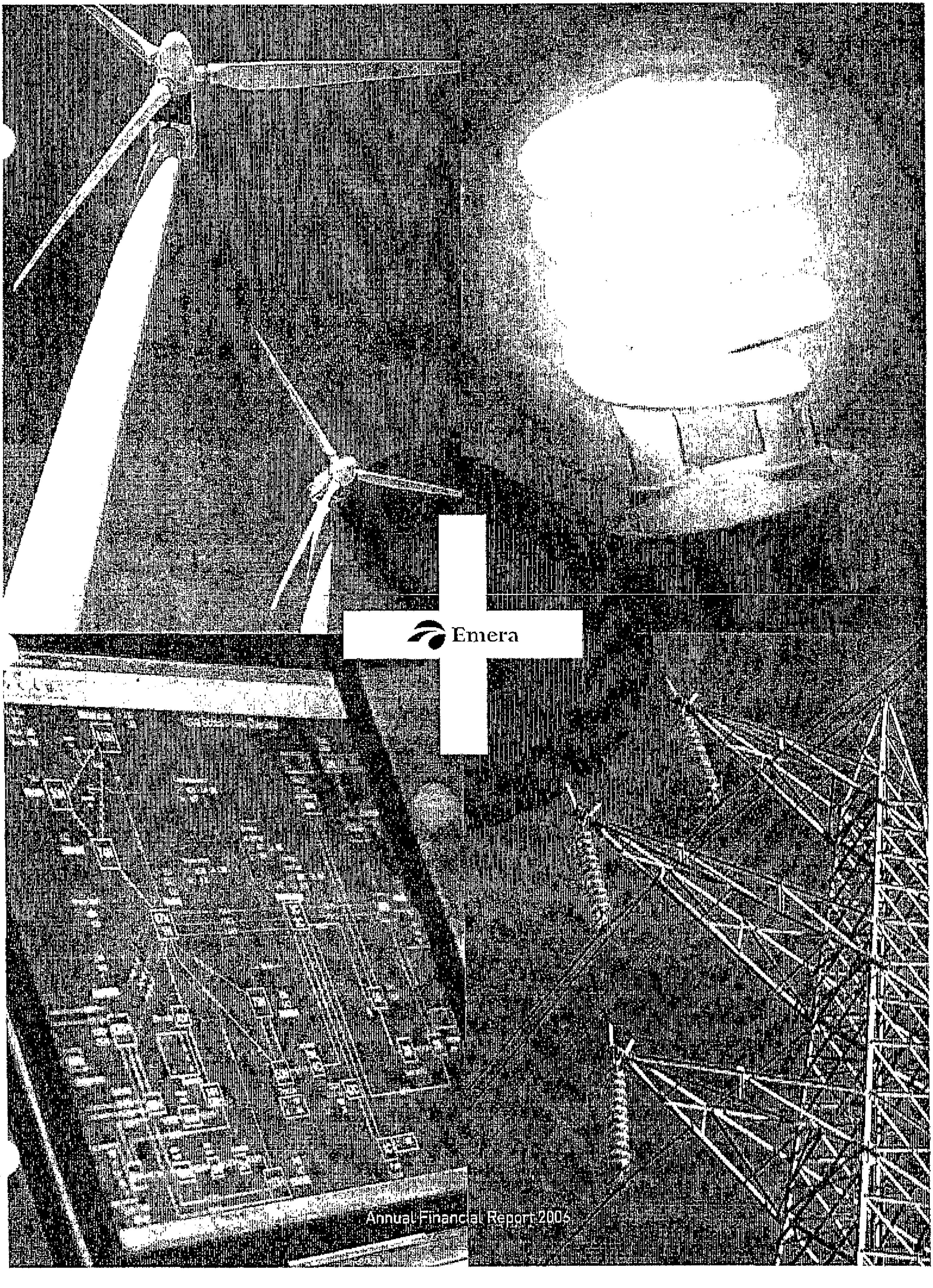
The number of customers served by ATCO Electric, NUY, NLD and YECL as at the end of each of the last two years was as follows:

	2006		2005	
	Number	%	Number	%
Industrial	10,894	5	10,847	5
Commercial	29,284	13	28,673	14
Residential	146,503	68	141,806	67
Rural, REAs and other	29,657	14	29,536	14
Total	216,338	100	210,862	100

ATCO Electric, NUY, NLD and YECL own and operate extensive electric transmission and distribution systems. The systems consist of approximately 9,300 km of main transmission lines and 60,800 km of distribution lines. In addition, ATCO Electric delivers power to and operates approximately 12,000 km of REA-owned distribution lines.

ATCO Electric, NUY, NLD and YECL own and operate 28 diesel, natural gas turbine and hydro generating plants having an aggregate nameplate capacity of 61 megawatts in Alberta and in the Yukon and Northwest Territories. The maximum peak load demand for these plants during the year ended December 31, 2006, was 32 megawatts.

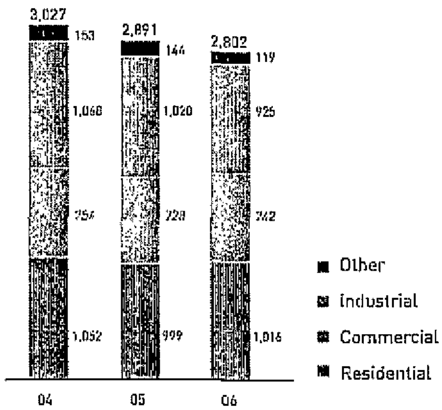
In August 2006, the AEUB approved the first phase of the AESO's application for the need to improve transmission infrastructure in northwest Alberta. The AEUB decision grants the AESO approval to assign approximately $300 million in projects to the Transmission Facility Owner, ATCO Electric. Once assigned by the AESO, ATCO Electric will prepare and file facility applications with the AEUB. Construction will commence once approval to proceed is received from the AEUB. The entire project was originally intended to be completed by 2009, but now is anticipated to be completed by 2011. As a result of price escalation caused by the change in completion date, coupled with the increasing costs of construction in Alberta, the entire project is now estimated to cost $400 million.


Emera
Annual Financial Report 2006

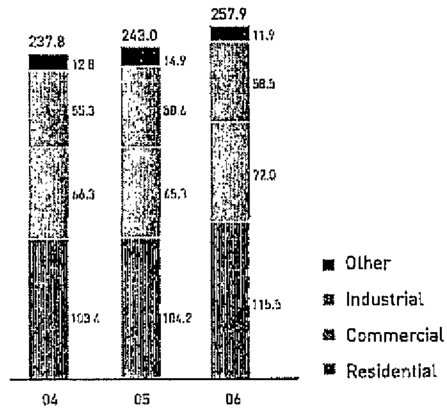
EMERA 2006

ELECTRIC REVENUE

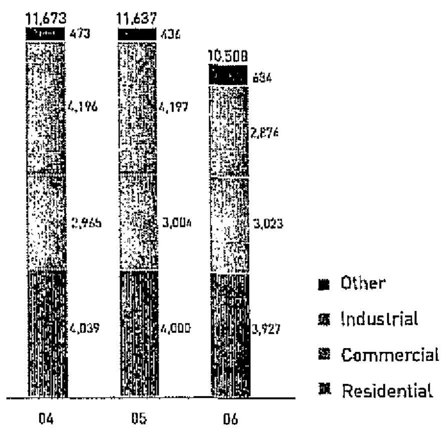
Q4 Electric Sales Volume
Gigawatt hours ("GWh")



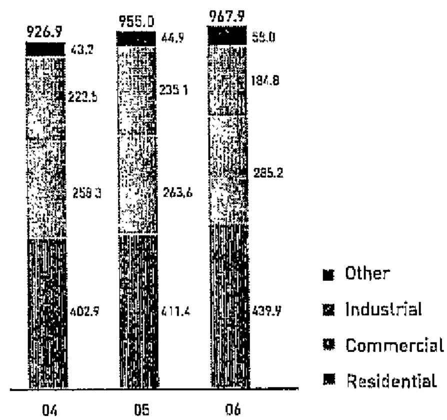
Q4 Electric Sales Revenues
millions of dollars



YTD Electric Sales Volume
GWh



YTD Electric Sales Revenues
millions of dollars



ENBRIDGE GAS DISTRIBUTION INC.

CUSTOMERS, VOLUMES AND REVENUES BY RATE CLASS
CALENDAR 2005 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)
General Service				
1.1.1	Rate 1 - Sales	972 744	2 903.6	1 429.5
1.1.2	Rate 1 - T-Service	613 199	1 776.9	336.5
1.1	Total Rate 1	1 585 943	4 680.5	1 766.0
1.2.1	Rate 6 - Sales	89 260	1 519.8	677.5
1.2.2	Rate 6 - T-Service	57 998	1 814.5	212.2
1.2	Total Rate 6	147 258	3 334.3	889.7
1.3.1	Rate 9 - Sales	26	3.3	1.4
1.3.2	Rate 9 - T-Service	8	1.4	0.2
1.3	Total Rate 9	34	4.7	1.6
1.	Total General Service Sales & T-Service	1 733 235	8 019.5	2 657.3
Contract Sales				
2.1	Rate 100	257	178.7	73.7
2.2	Rate 110	24	30.3	11.7
2.3	Rate 115	4	38.7	14.6
2.4	Rate 135	2	1.8	0.7
2.5	Rate 145	17	28.5	10.4
2.6	Rate 170	3	52.7	17.8
2.7	Rate 200	1	152.4	47.9
2.	Total Contract Sales	308	483.1	176.8
Contract T-Service				
3.1	Rate 100	1 799	1 239.3	115.0
3.2	Rate 110	280	635.3	40.3
3.3	Rate 115	55	861.2	37.1
3.4	Rate 125	0	0.0	0.0
3.5	Rate 135	36	57.5	2.7
3.6	Rate 145	161	214.1	13.8
3.7	Rate 170	32	663.3	21.2
3.8	Rate 300	0	5.5	0.1
3.9	Rate 305	1	31.0	0.1
3.	Total Contract T-Service	2 364	3 707.2	230.3
4.	Total Contract Sales & T-Service	2 672	4 190.3	407.1
5.	Total	1 735 907	12 209.8	3 064.4

* Less than $50,000

Witnesses: I. Chan
T. Ladanyi

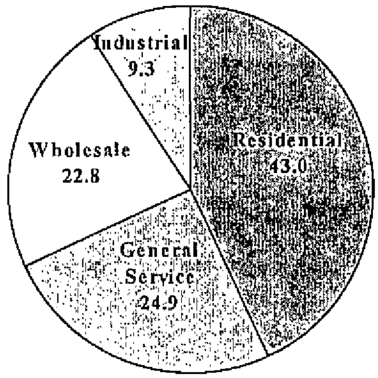
FORTISBC

FortisBC Inc.

Annual Information Form
For the Year Ended December 31, 2006

March 8, 2007

Allocation of 2006 Electricity Revenue by Customer Class



Performance-Based Rate Setting

The PBR framework uses a cost-of-service methodology, as described above, to establish periodic revenue requirements and customer rates for a base year. In subsequent years, for a pre-defined PBR term some or all components of rates may be determined automatically by a prescribed formula, such as that applied to FortisBC's gross operating and maintenance expense described in "The Business of FortisBC - Regulation". The periodic "rebasing" of revenue requirements provides for recovery of prudently incurred operating costs and an appropriate return on capital, and generally includes a mechanism for the recovery of extraordinary costs or costs outside the control of management.

In a PBR framework, the shareholder is afforded the opportunity to enhance its returns by sharing cost savings with its customers. In order to ensure that a utility does not compromise quality of service in an effort to realize increased shareholder returns, non-financial performance standards are defined, and may serve as thresholds for retaining a share of financial incentives.

FortisBC maintains and reports to the regulator and stakeholders its performance in the areas of system reliability, safety and health, generator reliability and customer service. Meeting satisfactory standards of performance in these areas generally leads to the BCUC approving FortisBC's participation in any achieved savings. A failure to achieve satisfactory standards of performance does not lead to financial penalties against the Corporation. In general, the Corporation has met the standards set by the BCUC since its initial PBR term beginning in 1996.

MARKET FOR SECURITIES

None of the issued and outstanding shares of the Corporation or any of its debentures are listed on any exchange.

CAPITAL STRUCTURE

FortisBC's business requires the Corporation to have ongoing access to capital to allow it to build and maintain the electrical systems in its service territory. In order to ensure that this access to capital is maintained and in accordance with BCUC requirements, the Corporation targets a long-term capital structure that includes 40% equity and 60% debt.

Share Capital

The Corporation's authorized share capital consists of 500 million common shares with a par value of $100 each and 500 million preferred shares with a par value of $25 each, of which 20,000 shares have been designated as Preferred Shares - Series 1, and 480,000 shares have been designated as Cumulative

FORTIS ALBERTA

Annual Information Form
Year Ended December 31, 2006

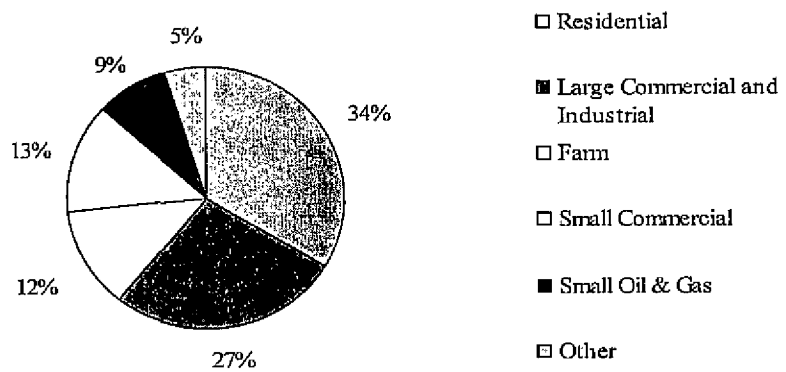
March 30, 2007

Billing determinants are either fixed or variable, with fixed billing determinants providing more revenue stability and minimizing the impact of fluctuations in the volume of electricity distributed. FortisAlberta's distribution revenue, based on 2006 rates, can be considered stable as approximately 85% of distribution revenue is derived from fixed or largely fixed billing determinants. FortisAlberta's billing determinants include:

- Energy (variable charges)
- Demand (largely fixed charges)
- Basic Monthly Charges (fixed charges)
- Contract Kilometers (fixed distance-based charges)

For example, monthly distribution charges to residential customers are based on a basic monthly charge ($/month) plus all energy (¢/kWh) delivered, whereas distribution charges to large industrial customers are based on monthly peak demand ($/kW/month) and the length of conductor required for each customer ($/km/month). The chart below provides an illustrative example of how cost allocation in Phase II results in recovery of the revenue requirement from customer classes (the chart does not necessarily represent all the customer classes, or the relative size of such customer classes, involved in recovery of the revenue requirement).

Allocation of Revenue Requirement by Customer Class

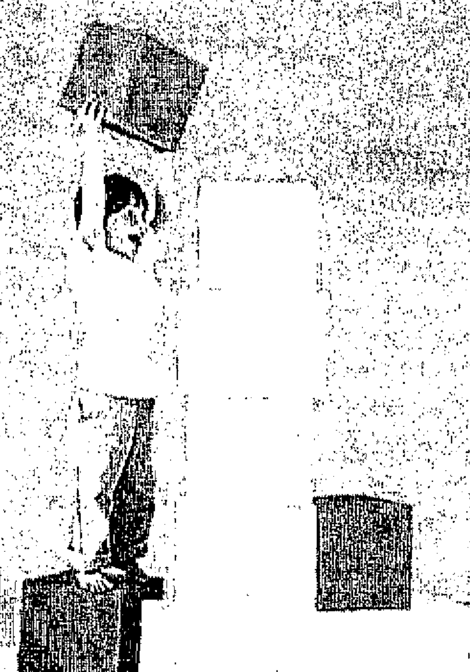


In general, a full Phase I and Phase II process may take up to a year from original application to final decision by the EUB. The distribution utility may also negotiate Phase I and Phase II components with stakeholders as an alternative to the regulatory quasi-judicial process. Negotiated settlements still require review and final approval by the EUB.

On July 2, 2004, the EUB issued the Generic Cost of Capital Decision which established a common approach for setting the ROE for all electricity and natural gas utilities under its jurisdiction. This decision also established a deemed capital structure, expressed as proportions of debt and equity, for rate-setting purposes for each regulated electricity and natural gas utility. Each such capital structure represents how a utility is deemed to be financing its rate base assets. These deemed capital structures are to be used by the EUB in determining future rates in the absence of negotiated settlements.

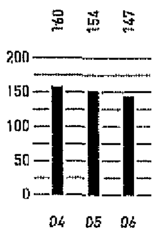
The EUB has determined that to the extent any utility-specific adjustments to the common ROE may be necessary, they are to be addressed by way of modifications to the deemed capital structure (i.e., the equity to debt ratio) of that particular utility. Accordingly, the EUB has established a deemed capital structure for each electricity and gas utility that it regulates that takes into account the following factors: (i) the business

ANNUAL REPORT

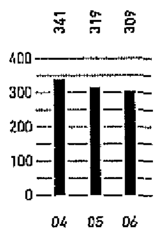


HIGHLIGHTS

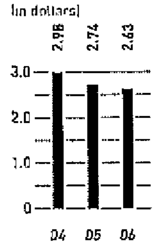
PARTNERS' INCOME
(in millions of dollars)



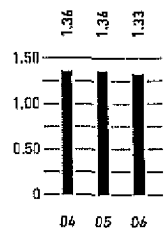
CASH FLOW RELATED TO OPERATING ACTIVITIES
(in millions of dollars)



CASH FLOW RELATED TO OPERATION ACTIVITIES PER UNIT
(in dollars)



DISTRIBUTION PAID PER UNIT
(in dollars)



Years ended September 30, (in millions of dollars, except for unit data which is in dollars)	2006	2005
CONSOLIDATED INCOME AND CASH FLOWS		
Revenues	$2,003.8	$1,808.2
Gross margin	$ 576.3	$ 563.2
Income before interest, taxes and amortization	$ 391.6	$ 387.6
Partners' income	$ 147.2	$ 154.4
Cash flows related to operating activities (before working capital)	$ 297.3	$ 345.5
Capital expenditures and deferred charges	$ 190.9	$ 239.0
Partners' income per unit		
Basic	$ 1.25	$ 1.33
Diluted	$ 1.25	$ 1.33
Distributions paid per unit	$ 1.33	$ 1.36
Weighted average number of outstanding units (in millions)	117.5	116.5
Interest coverage on consolidated long-term debt over a period of 12 months (times)	2.75	2.87
CONSOLIDATED NORMALIZED VOLUMES (1) (in millions of cubic metres)		
MARKETS		
Industrial	3,116	2,987
Commercial	1,873	1,897
Residential	728	734
Total	5,717	5,618
OTHER INFORMATION		
Authorized rate of return on deemed common equity (Quebec distribution activity)	9.33%	11.64%
Credit ratings		
Long-term bonds (2) (S&P/DBRS)	A/A	A/A
Commercial paper (2) (S&P/DBRS)	A-1(low)/R-1(low)	A-1(low)/R-1(low)
Stability of distributions (S&P/DBRS)	SR-2/STA-2(average)	SR-1/STA-1(low)
Market prices on Toronto Stock Exchange (in dollars):		
High	$ 22.50	$ 23.45
Low	$ 15.56	$ 20.68
Close	$ 17.60	$ 22.50
Public ownership in Partnership (non-controlling Partners)	27.2%	27.2%
CONSOLIDATED BALANCE SHEETS		
Total assets	$2,783.2	$2,880.1
Total debt	$1,433.0	$1,411.6
Partners' equity	$ 924.6	$ 938.4
Partners' equity per unit	$ 7.87	$ 7.99

(1) Estimated volumes at normal temperatures in Quebec only
(2) Through its General Partner, Gaz Métro Inc.

PACIFIC NORTHERN GAS ANNUAL REPORT 2006

PNG

YEARS ENDED DECEMBER 31	2006	2005	2004	2003	2002
OPERATING DATA					
DELIVERIES (TJ)					
Sales					
Residential	3 066	3 135	3 279	3 464	3 503
Commercial	2 706	2 659	2 655	2 845	2 898
Small industrial	710	689	778	825	1 050
Large industrial	523	506	626	620	594
	7 005	6 989	7 338	7 754	8 045
Transportation					
Commercial	157	61	60	64	69
Small industrial	2 774	2 887	2 958	2 764	2 755
Large industrial – Methanex	3	20 497	25 952	23 820	25 552
Large industrial – other	2 456	2 410	2 663	2 236	3 042
	5 390	25 855	31 633	28 884	31 418
TOTAL DELIVERIES	12 395	32 844	38 971	36 638	39 463
Customers at year end	39,511	39,295	39,291	39,106	39,254
Degree days					
Actual	4,856	4,655	4,895	5,153	5,204
Normal	5,070	5,123	5,148	5,155	5,104
Actual as a percent of normal	96%	91%	95%	100%	102%

Degree day is a measure of coldness. It is calculated by accumulating for each day in the fiscal period the total number of degrees by which the daily mean temperature fell below 18 degrees Celsius. The figures given are the average for all service areas, weighted by deliveries.

FINANCIAL DATA ($ in thousands)	2006	2005	2004	2003	2002
REVENUE					
Sales					
Residential	44,919	42,354	37,627	38,815	30,204
Commercial	34,241	31,546	26,488	28,196	22,213
Small industrial	7,152	5,599	5,746	6,840	7,151
Large industrial	5,087	5,370	5,032	5,026	3,292
	91,399	84,869	74,893	78,877	62,860
Transportation					
Commercial	630	217	197	182	182
Small industrial	3,308	3,188	2,839	2,705	2,328
Large industrial – Methanex	1,822	12,182	12,191	12,344	20,589
Large industrial – other	2,945	2,824	3,175	5,688	3,670
	8,705	18,411	18,402	20,919	26,769
Off-system sales	32,713	56,159	43,949	33,403	18,763
Methanex termination amortization	5,552	–	–	–	–
Other	479	511	511	528	671
TOTAL REVENUES	138,848	159,950	137,755	133,727	109,063
EXPENSES					
Cost of sales	91,118	111,287	88,954	84,417	56,820
Operating	17,026	17,166	18,716	18,471	19,164
Interest	9,673	7,537	7,976	8,053	7,642
Municipal and other taxes	4,755	4,120	3,941	3,982	4,259
Depreciation and amortization	8,378	8,766	8,640	8,376	9,653
Income taxes	2,947	4,414	4,120	4,760	6,935
	133,897	153,290	132,347	128,059	104,473
NET INCOME	4,951	6,660	5,408	5,668	4,590
Net income applicable to common shares	4,614	6,323	5,071	5,331	4,253

Terasen Gas Inc.
A subsidiary of Kinder Morgan, Inc.

Annual Information Form

For the Year Ended December 31, 2006
dated
April 2, 2007

Operating Summary for Terasen Gas

Dollar amounts in millions *Years ended December 31*	**2006**	2005	2004
Revenues			
Residential	**$ 922.4**	$ 883.7	$ 778.2
Commercial	**463.6**	441.3	392.0
Small industrial	**41.7**	42.8	43.5
Large industrial and other	**2.2**	2.9	3.6
Total natural gas sales revenue	**1,429.9**	1,370.7	1,217.3
Transportation	**73.6**	71.2	65.5
Other	**21.8**	24.0	22.4
Total natural gas revenue	**$ 1,525.3**	$ 1,465.9	$ 1,305.2
Volumes (PJs)[1]			
Residential	**68.7**	69.4	66.5
Commercial	**38.4**	39.1	38.3
Small industrial	**3.8**	4.2	4.9
Large industrial and other	**0.2**	0.3	0.4
Total natural gas sales volume	**111.1**	113.0	110.1
Transportation	**62.3**	63.9	62.8
Other	**36.8**	36.4	39.3
Total natural gas volume	**210.2**	213.3	212.2
Customers at year end			
Residential	**733,598**	723,898	712,304
Commercial	**79,113**	78,497	77,624
Small industrial	**325**	396	416
Large industrial and other	**40**	45	45
Transportation	**1,956**	1,907	1,741
	815,032	804,743	792,130
Customers statistics			
Average use per customer (GJs)			
Residential	**94**	97	95
Commercial	**485**	501	495
Average rate per GJ			
Residential	$ 13.42	$ 12.73	$ 11.70
Commercial	$ 12.07	$ 11.29	$ 10.23
Natural gas purchased (PJs)	**111.1**	113.3	110.2
Maximum day sendout (TJs) (including interruptible)	**1,349.6**	1,483.3	1,473.2
Approved rate base	**$ 2,516.0**	$ 2,406.0	$ 2,310.1
Degree days (Base 18°C)[2]			
Coastal – Actual	**2,714**	2,664	2,525
– Normal	**2,765**	2,756	2,771
Interior – Actual	**3,753**	3,858	3,760
– Normal	**3,901**	3,902	3,895

[1] *Volume statistics are stated in SI (metric) units*
[2] *A degree-day is approximately equal to 18 deg C minus the daily average temperature in the corresponding region. The normal period is based on a 20-year basis.*

UNION GAS LIMITED
Summary of Gas Sales, Delivery and Transportation
All Customer Rate Classes
Year Ended December 31, 2004

Line No.	Particulars	Customers Year End (2) (a)	Total Volume (10^3m^3) (b)		Total Gas Sales Revenue ($000) (c)		Total Delivery Revenue ($000) (d)		Average Unit Rate (1) ($/m^3$) (e) (d) / (b)
	General Service								
1	Rate M2	935,557	3,945,274	$	1,039,638	$	392,304	$	0.09944
2	Rate 01	285,201	919,322		322,155		129,415		0.14077
3	Rate 10	2,914	384,086		78,888		20,644		0.05375
4	Rate 16	0	55		20		4		0.07887
5	Total General Service	1,223,672	5,248,737	$	1,440,701	$	542,368	$	0.10333
6	% of Total (line 28)	99.95%	36.32%		88.33%		80.65%		
	Wholesale - Utility								
7	Rate M9 Firm	2	24,769	$	662	$	664	$	0.02679
8	Rate M10 Firm	3	262		85		9		0.03524
9	Rate 77 Firm	1	0		28		28		0.00000
10	Total Wholesale - Utility	6	25,031	$	776	$	701	$	0.02801
11	% of Total (line 28)	0.00%	0.17%		0.05%		0.10%		
	Contract								
12	Rate M4	204	658,982	$	25,905	$	19,741	$	0.02996
13	Rate M6	0	0		0		0		0.00000
14	Rate M7	11	1,027,612		16,932		16,934		0.01648
15	Rate 20 Storage		0		22		22		
16	Rate 20 Transportation	63	470,929		23,872		7,230		0.01535
17	Rate 100 Storage		0		1,779		1,779		
18	Rate 100 Transportation	19	2,514,199		17,334		17,030		0.00677
19	Rate T-1 Storage		0		7,914		7,914		
20	Rate T-1 Transportation	47	3,375,423		36,802		36,802		0.01090
21	Rate T-3 Storage		0		1,359		1,359		
22	Rate T-3 Transportation	1	293,522		4,915		4,915		0.01674
23	Rate M5	136	559,104		10,997		10,757		0.01924
24	Rate 25	116	279,710		41,667		4,939		0.01766
25	Rate 30	1	0		-5		-5		0.00000
26	Total Contract	598	9,179,480	$	189,493	$	129,417	$	0.01410
27	% of Total (line 28)	0.05%	63.51%		11.62%		19.24%		
28	Total	1,224,276	14,453,249	$	1,630,970	$	672,486	$	0.04653

Note:
(1) The average unit rates are calculated using total delivery revenue including both fixed components (monthly charge, demand) and variable volumetric components.
(2) Customer count for storage is included in the transportation customer count.