uniongas
A Spectra Energy Company

April 27, 2007

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, ON
M4P 1E4

Re: Union_APPL_deferralbalanceESM_20070427
EB-2007-0598

Dear Ms. Walli:

Enclosed is an application and evidence from Union Gas Limited ("Union") concerning the final disposition and recovery of certain 2006 year-end deferral account balances and the 2006 year-end earnings sharing amount.

Union proposes that the impacts which result from the disposition of 2006 deferral account balances and 2006 earnings sharing be implemented on July 1, 2007 to align with other potential rate changes expected to result from the July QRAM proceeding.

Also, consistent with the Board's Rate Order for EB-2006-0057 (concerning the disposition of Union's 2005 deferral account balances and earnings sharing amount) Union is proposing that interest accrue starting January 1, 2007 on the amount due to ratepayers as a result of the continuation of 2006 earnings sharing mechanism approved for 2005 at the interest rate for deferral and variance accounts approved by the Board in EB-2006-0117. This approach is consistent with how the balance would have been treated had a deferral account been established to record this amount.

Finally, Union notes that Section 36 (4.2) states requires that with respect to non-commodity related deferral accounts *"the Board shall at least once every 12 months, or such period as is prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates."* These deferral accounts were last disposed of by the Board in its EB-2006-0057 Decision and Order dated August 2, 2006.

If you have any questions concerning this application and evidence please contact me at (519) 436-5476.

Yours truly,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

cc M. Penny (Torys)
EB-2005-0520 Intervenors

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2007;

APPLICATION

1. Union Gas Limited ("Union") is a business corporation, incorporated under the laws of Ontario, with its head office in the Municipality of Chatham-Kent.

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storing gas within the meaning of the *Ontario Energy Board Act, 1998* (the "Act").

3. In RP-2003-0063, Union applied to the OEB for an order, among other things, approving or fixing just and reasonable rates and other charges for the sale, distribution, storage and transmission of gas by Union effective January 1, 2004.

4. By Reasons for Decision and Rate Order dated March 18, 2004, the OEB fixed such rates. In fixing such rates, the OEB approved the creation/continuation of certain deferral accounts.

5. In EB-2004-0480, by Reasons for Decision and Rate Order dated December 15, 2004, the OEB directed that Union is subjected to a 50:50 earnings sharing mechanism with no deadband for its 2005 fiscal year.

6. In EB-2005-0449, by Decision and Order dated December 12, 2005, the OEB directed Union to continue the earnings sharing mechanism currently in place, into 2006.

7. In EB-2005-0189, by Decision and Order dated March 18, 2005, the OEB specified the use of the October consensus interest rate to calculate the benchmark rate of return on common equity for purposes of calculating any excess earnings in the earnings sharing mechanism. The Decision also confirmed that any excess earnings shall reflect normalization for weather.

8. In EB-2005-0507, by Order dated March 29, 2006, the OEB ordered that the Shared Savings Mechanism Variance Account (Account No., 179-115) ("SSMVA") operate in the same manner as approved for 2005. The operation of the SSMA for 2005 was prescribed in the EB-2005-0211 Settlement Agreement dated April 7, 2005 and accepted by the Board on April 26, 2005. That Settlement Agreement specified that the establishment of a DSM Shared savings Mechanism (SSM) with any 2005 SSM payout be outside of any earnings sharing mechanism.

9. Union therefore applies for:

   a) approval of final balances for all 2006 deferral accounts and an order for final disposition of those balances; and

   b) approval of the earnings sharing amount for 2006 and an order for final disposition of that earnings sharing amount.

10. Union also applies to the OEB for such interim order or orders approving interim rates or other charges and accounting orders as may from time to time appear appropriate or necessary.

11. Union further applies to the Board for all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.

12. This application will be supported by written evidence. This evidence will be pre-filed and will be amended from time to time as required by the OEB, or as circumstances may require.

13. The persons affected by this application are the customers resident or located in the municipalities, police villages and Indian reserves served by Union, together with those to whom Union sells gas, or on whose behalf Union distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

14. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1
Attention: Chris Ripley
Manager, Regulatory Applications

Telephone: (519) 436- 5476

Fax: (519) 436-4641

- and -

Torys LLP
Suite 3000, Maritime Life Tower
P.O. Box 270
Toronto-Dominion Centre
Toronto, Ontario
M5K 1N2
Attention: Michael A. Penny

Telephone: (416) 865-7526

Fax: (416) 865-7380

DATED: April 27, 2007.

UNION GAS LIMITED

By its Solicitors

Torys
Suite 3000, Maritime Life Tower
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1. 2006 YEAR-END DEFERRAL ACCOUNT BALANCES

At the end of December 2006, the balances accumulated in Union's Board-approved deferral accounts total a credit of $179.570 million. This amount consists of $197.803 million in credits in gas supply-related deferral accounts (the majority of which is managed through the Quarterly Rate Adjustment Mechanism ("QRAM")), $16.990 million in credits in Storage and Transportation related deferral accounts, and $35.224 million in debits in the Other deferral accounts. Individual account balances are shown at Tab 1, Schedule 1. Each account balance includes interest up to December 31, 2006. Interest is computed monthly on the opening balance of each account. The applicable interest rate used is the short-term debt rate of 4.15% approved by the Board in the RP-2003-0063 proceeding.

Deferral account balances have been categorized into three types: Gas Supply deferral accounts, S&T deferral accounts and Other deferral accounts. The balances for each account are discussed below.

GAS SUPPLY DEFERRAL ACCOUNTS

The balances recorded in the following gas supply related deferral accounts were examined in each of Union's four QRAM applications in 2006.

	179-105	North Purchased Gas Variance Account ("PGVA")
	179-100	TCPL Tolls and fuel – Northern and Eastern Operations area
	179-106	South PGVA
	179-109	Inventory Revaluation
	179-107	Spot Gas Variance Account

Union's Board-approved QRAM process establishes reference prices for selected gas supply-related deferral accounts and the prospective recovery, or refund, of the projected balances of these accounts including interest, over the following 12 month period. Variances between the forecast and actual prospective recovery amounts are tracked and included in the amounts prospectively recovered in future QRAM proceedings.

Under the QRAM process, the actual year-end deferral account balances are subject to the Board's final approval. In this application, Union is seeking that approval. The Board approved all four of Union's QRAM applications in 2006.

The balances for the two other gas supply related deferral accounts are not prospectively recovered or refunded as part of the approved QRAM process. These accounts are as follows:

Account No. 179-108 UDC

Account No. 179-89 Heating Value

Account No. 179-108 Unabsorbed Demand Costs

The credit balance of $0.708 million in the Unabsorbed Demand Costs ("UDC") account is the difference between the actual UDC incurred by Union and the amount of UDC included in rates as approved by the Board.

During 2006 Union experienced excess supply of 12.680 PJs due to both planned UDC and reduced demand caused by weather being 14% warmer than normal. The 2006 weather normal is set by the blended 70:30 (30 year average/20 year trend) weather normal methodology in accordance with the Board's RP-2003-0063 Decision. In response to the warmer than normal weather in 2006, Union reduced a portion of its planned purchases through the spring and summer to balance demand and supply. The resulting unfilled pipe capacity was sold for the then-current market prices which minimized UDC to the extent possible. The favourable cost variance more than offset the unfavourable volume variance which resulted in less UDC overall than had been forecast. The explanation for the excess supply of 12.680 PJs is shown in Table 1 below:

Table 1

	Northern and Eastern Operations area (PJs)	Southern Operations area (PJs)	Total Franchise area (PJs)
Planned UDC	4.091	1.823	5.914
Weather-related UDC	2.713	4.053	6.766
Total UDC	6.804	5.876	12.680
% of Total	53.7%	46.3%	100.0%

A description of each item follows:

1. Planned UDC

To meet peak customer demands across Union's franchise area and the targeted storage inventory levels at October 31, Union's 2006 supply portfolio included planned UDC of 4.091 PJs in the Northern and Eastern Operations area and 1.823 PJs in the Southern Operations area.

2. Weather-related UDC

The weather through the 2006 heating season was abnormally warm, resulting in reduced demand across Union's franchise area. In the Northern and Eastern Operations area, the sales service and bundled direct purchase customers experienced reduced demand of 2.713 PJs due to weather. In the Southern Operations area, the sales service customers experienced reduced demand of 4.053 PJs. Union did not incur UDC on behalf of direct purchase customers in the

Southern Operations area because these customers manage their own supplies to meet their load balancing checkpoint targets.

3. Total Excess Supply

The result of the planned UDC and the reduced demand due to weather was 6.804 PJs (or 53.7% of the total) of excess supply in the Northern and Eastern Operations area and 5.876 PJs (or 46.3% of the total) in the Southern Operations area.

For 2006, Union's total UDC was $1.007 million. Union collected $1.692 million in rates and recorded an associated interest credit of $0.023 million. The result is a credit in the UDC deferral account of $0.708 million. Table 2 below provides the derivation of the UDC deferral account balances by operating area.

Table 2

	Northern and Eastern Operations area ($ 000s)	Southern Operations area ($ 000s)	Total Franchise area ($ 000s)
UDC Costs Incurred	541	466	1,007
Collected in Rates	(1,692)	-	(1,692)
Interest	(43)	20	(23)
(Credit)/Debit to Operations areas	(1,194)	486	(708)

A description of each item follows:

1. UDC Costs Incurred

   Union proposes to assign the total cost of $1.007 million to each operating area in proportion to the excess supply as calculated in Table 1. This results in UDC of $0.541 million for the Northern and Eastern Operations area and $0.466 million for the Southern Operations area.

2. Collected in Rates

   Board-approved rates for 2006 included $1.932 million associated with planned UDC in the North (RP-2003-0063, Rate Working Papers, Schedule 27, page 3). No UDC was planned for or included Southern rates. For 2006, Union actually recovered $1.692 million of the $1.932 million.

3. Interest

   Interest associated with UDC costs amounted to a credit of $0.043 million for the Northern and Eastern Operations area and debit of $0.020 million for the Southern Operations area for a net amount of $0.023 million.

4. (Credit)/Debit to Operations areas

The UDC deferral account has a net total credit balance of $0.708 million. The balance applicable to customers in the Northern and Eastern Operations area is a credit of $1.194 million. The balance applicable to customers in the Southern Operations area is a debit of $0.486 million.

Account No.179-89 Heating Value

The Heating Value deferral account captures the impact associated with the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates. The 2006 credit balance of $2.405 million is due to lower energy content in the gas delivered to customers than what was reflected in their gas supply rates.

STORAGE AND TRANSPORTATION DEFERRAL ACCOUNTS

Actual net revenues from storage and transportation services are deferred against the net revenues included in the rates approved by the Board in the RP-2003-0063 Rate Order. Balances in S&T deferral accounts are currently shared on a 75/25 basis between ratepayers and the shareholder. The current credit balance of $16.990 million represents the ratepayer portion in the following S&T deferral accounts.

Account No. 179-69 Transportation and Exchange Services

The balance in the Transportation and Exchange Services deferral account is the difference between actual net revenues for Transportation and Exchange Services including C1 Interruptible Transportation, Energy Exchanges, M12 Transportation Overrun, M12 and C1 Non-Loss-of-Critical-Unit Protected Firm Transportation, M12 Limited Firm/Interruptible Transportation and C1 Firm Short Term Transportation, and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $4.004 million is 75% of the variance between the Board-approved forecast of $0.688 million and actual net revenues of $6.027 million. The total variance of $5.339 million is primarily attributable to one customer's use of Union's M12 Overrun services; and exchange services sold as a result of warmer than normal weather.

Account No. 179-70 Short-Term Storage and Other Balancing Services

The balance in the Short-Term Storage and Other Balancing Services deferral account is the difference between actual revenues in excess of the costs to provide Short-term Storage and Other Balancing Services (including C1 Off-Peak Storage, Gas Loans, Consumers' LBA, Supplemental Balancing Services, C1 Firm Peak Storage, C1 Firm Short-Term Deliverability and M12 Interruptible Deliverability) and the forecast revenue in excess of the cost to provide these services as approved by the Board for ratemaking purposes.

Table 3 below shows the comparison of the actual 2006 net revenue sufficiency from Short-Term Storage and Other Balancing Services of $35.547 million to the net revenue sufficiency from Short-Term Storage and Other Balancing Services approved by the Board in 2004 of $6.793 million. The result for the year is an increase in net revenue from Short-Term Storage and Other Balancing Services of $28.754 million The cost of gas required to provide the for Short-Term Storage and Other Balancing Services is deducted from the revenue to calculate the net revenue sufficiency.

The credit balance in the Short-Term Storage and Other Balancing Services deferral account of $21.565 million is 75% of the variance between the Board approved forecast revenue in excess of the approved revenue requirement of $6.793 million and actual revenue excess of $35.547 million. The total variance of $28.754 million is primarily the result of increased sales of C1 peak storage services, off peak storage services and loan services.

Account No. 179-72 Long-Term Peak Storage Services

The balance in the Long-Term Peak Storage Service deferral account is the difference between actual revenue in excess of the costs to provide Long-Term Peak Storage Services including C1 Firm Peak Storage and the revenue forecast in excess of the cost to provide these services as approved by the Board for ratemaking purposes.

Table 3 below shows the comparison of the actual 2006 net revenue sufficiency for Long-Term Peak Storage Services of $5.510 million to the net revenue sufficiency for Long-Term Peak Storage Services approved by the Board in 2004 of $17.965 million. The result is a decrease from the Board approved net revenue from Long-Term Peak Storage Services of $12.455 million. The costs to provide Long-Term Peak Storage Services are deducted from the revenue to calculate the net revenue sufficiency. These costs include the cost of gas and the cost of owning and operating the storage facilities including depreciation, interest, income taxes and the allowed return to the shareholder.

The debit balance of $9.341 million is 75% of the variance between the forecast revenue in excess of the cost to provide long-term peak storage of $17.965 million approved by the Board for rate setting purposes and actual revenue net of the cost to provide long term peak storage service of $5.510 million. The decrease of $12.455 million is primarily due to an increase in deferred income tax expense of $10.524 million related to storage service as a result of the change in regulation for storage services provided to customers outside of Union's franchise area.

Table 3

Calculation of the Deferral Account Balances for Account Nos. 179-70 and 179-72
($ millions)

			Deferral Accounts	
Line No.		Total	Short-Term Storage and Other Balancing Services (No 179-70)	Long-Term Peak Storage Services (No 179-72)
1	Actual storage revenue - 2006	89.510	45.940	43.570
2	Cost to provide service	48.453	10.393	38.060
3	Net revenue sufficiency (Line 1- Line 2)	41.057	35.547	5.510
4	Approved storage revenue - 2004	44.747	7.694	37.053
5	Cost to provide service	19.989	0.901	19.088
6	Net revenue sufficiency (Line 4- Line 5)	24.758	6.793	17.965
7	Variance (Line 3- Line 6)	16.299	28.754	(12.455)
8	Ratepayer portion deferred (Line 7 x 75%)	12.224	21.565	(9.341)
9	Deferral Account Balance	(12.224)	(21.565)	9.341

Accounting for deferred income taxes

Included in the actual cost to provide storage services in 2006 is an increase in deferred income tax expenses of $10.524 million resulting from the Board's decision in the Natural Gas Electricity Interface Review ("NGEIR") to refrain from regulating rates for storage services to customers outside Union's franchise area and rates for new storage services to customers within the franchise area.

Prior to 1997, Union recorded income tax expense using the tax allocation (deferred or normalized) method. Under this method the company's annual income tax expense recorded in the accounts and recovered from customers in rates included both the amount of current and future income taxes payable in the year. Under the tax allocation method deferred income taxes expenses are recorded as a result of claiming capital cost allowance for income taxes in excess of depreciation recorded in the accounts. There was a match between the period of recovery from customers and the activity that gave rise to the obligation.

In the E.B.R.O. 493 / 494 (1997 Rates) proceeding Union proposed and the Board approved a change the accounting treatment of income taxes from a normalized or deferred basis to a flow-through basis. This change was made in advance of Union's merger with Centra to have a consistent approach to tax accounting following the merger.

Between 1997 and November 2006, Union's income tax expense was recorded using the flow through tax accounting methodology. Under flow through tax accounting, the company's income tax expenses recorded are income taxes currently payable only. Under Canadian generally accepted accounting principles ("GAAP"), rate-regulated entities are not required to record deferred (future) income tax expenses to the extent that these costs are expected to be recovered from customers in future rates. The impact of this change was to defer the recovery from customers of deferred income tax expenses from the period in which they were incurred to the period when the taxes are paid. To qualify as a rate regulated entity for the exemption for deferred taxes, a company must meet all of the following criteria:

a) Rates for services are subject to approval by a regulator;

b) Rates are designed to recover the cost of providing service; and

c) It is reasonable to assume that rates set to recover costs in the future can be charged to and collected from customers.

The following are excerpts from the Canadian Institute Chartered Accountants Handbook section 3465 guidance for accounting for income taxes for rate regulated entities:

DEFINITIONS AND BACKGROUND

.09 The following definitions have been adopted for purposes of this Section:

k) A rate-regulated enterprise is an enterprise that meets all of the following criteria:

(i) the rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products;

(ii) the regulated rates are designed to recover the cost of providing the services or products; and

(iii) it is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for amounts recorded as recoverable under the rate formula.

RATE-REGULATED ENTERPRISES

.102 A rate-regulated enterprise need not recognize future income taxes in accordance with this Section to the extent that future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. If future income taxes are not recognized in accordance with this Section, the rate-regulated enterprise should disclose the following, in addition to the information to be disclosed in accordance with paragraphs 3465.91-.92:

(a) the reason why future income tax liabilities and future income tax assets have not been recognized; and

(b) the amount of future income tax liabilities, future income tax assets and future income tax expense that have not been recognized. [JAN. 2000]

.104 Future income taxes would be recognized in accordance with the remainder of this Section to the extent that future income taxes are not expected to be included in the rates charged to customers in the future.

In November 2006, the Board issued its decision in the EB-2005-0551 proceeding, the NGEIR, to refrain from regulating rates for storage services to customers outside Union's franchise area and rates for new storage services to customers within the franchise area. This change in rate regulation for storage services meant that Union no longer met the criteria for rate regulated accounting set out in 3465.09 (k). Specifically, rates for these storage services are no longer approved by the regulator. Because there were deferred tax costs associated with activity in the 1997 to 2006 period related to the unregulated storage operations, and there is no future rate mechanism to allow recovery of these costs, Union recorded these expenses in accordance with section 3465.104.

Union has recorded deferred tax expense of $10.524 million related to the unregulated storage operations. These tax costs represent the portion of Union's unrecorded future income taxes from 1997 to 2006 related to the ex-franchise storage operation using the percentage of unregulated storage established in the NGEIR decision. The $10.524 million deferred tax expense has been included in the calculation of the amount of storage revenue to be refunded to ratepayers through the deferral accounts. The revenue required to recover the deferred tax expense is grossed up by $5.951 million to $16.475 million to recognize the current tax expense.

Union reflected the impact of the change in regulation in the 2006 financial results as this is when the Board determined that rates for these storage services would no longer be approved by the regulator, reflected in the overall cost of service revenue requirement and there is no future mechanism for recovering these costs. The result is reflected in the 2006 audited financial statements and disclosed in the Management Discussion & Analysis. The company's approach was reviewed by the external auditors Deloitte & Touche in connection with their year end audit and incorporated into their evaluation leading to their audit opinion accompanying the financial statements.

In addition, Union has retained the services of Ernst &Young to review and provide a written report on Union's application of accounting principles resulting from the Board's decision to forebear from regulating a portion of Union's storage operations. A copy of this report is attached as Appendix A.

Account No. 179-73 Other S&T Services

The balance in the Other S&T Services deferral account is the difference between actual net revenues for Other S&T Services including Off-System Capacity, Redirection/Name Changes, Ontario Production and Other S&T services and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $0.390 million is 75% of the variance between the Board-approved forecast of $0.460 million and actual net revenues of $0.980 million.

Account No. 179-74 Other Direct Purchase Services

The credit balance of $0.373 million in the Other Direct Purchase Services deferral account is 75% of the actual net revenues earned for Supplemental Load Balancing (T1 and R1) and T1 Storage Inventory Demand Charges. There were no revenues forecast in rates.

OTHER DEFERRAL ACCOUNTS

The other deferral account balances are discussed below.

Account No. 179-26 Deferred Customer Rebates/Charges

The Deferred Customer Rebates/Charges account has no balance. This account captures unclaimed cheques related to amounts refunded to customers that arose from the disposition of deferral balances as approved by the Board. Disposition of deferral accounts as approved by the Board in the EB 2005-0211 Rate Order were dealt with prospectively in rates from October 1 to December 31, 2006. As a result, no cheques were issued and none returned.

Account No. 179-56 Comprehensive Customer Information Program

The Comprehensive Customer Information Program captures the incremental costs associated with increasing customer awareness about changes in the natural gas market. No incremental costs were incurred in 2006 with respect to this Program. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No. 179-60 Direct Purchase Revenue and Payments

The credit balance of $0.171 million in the Direct Purchase Revenue and Payment deferral account is the difference between actual Delivery Commitment Credit ("DCC") payments made and the payment amount included in Board-approved rates. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No.179-75 Lost Revenue Adjustment Mechanism

The Lost Revenue Adjustment Mechanism ("LRAM") deferral account has a debit balance of $3.980 million which represents the difference between actual margin reductions related to Union's DSM activities and the margin reduction included in gas delivery rates as approved by the Board. This balance includes volume variances related to 2003, 2004, 2005 and 2006 DSM activities. Union proposes to dispose of the balance in the account of $3.980 million.

Tab 1, Schedule 2, page 1 provides the breakdown of the LRAM deferral account balance for each year from 2003 to 2006. Tab 1, Schedule 2, pages 2 to 5 provides the LRAM volumes and the corresponding revenue impacts related to 2003, 2004, 2005 and 2006 DSM activities respectively. The calculations for lost revenues reflect the Board's ruling in RP-2001-0029 Decision with Reasons at paragraph 2.170 which requires that the year one impact of DSM activities is equivalent to 50% of the savings in the first year in which the DSM measure is undertaken.

The amount related to 2003 is a credit balance of $0.145 million (Tab 1, Schedule 2, page 2, line 15, column (n)) which is composed of the following:

- the variance between lost revenues resulting from the audited volumes of 38,860 $10^3 m^3$ and those reflected in rates
- less the lost revenues for 2003 DSM activities which were approved by the Board for disposition in EB-2006-0057.

The audit of 2004 DSM volumes is complete. The amount related to 2004 is a debit balance of $0.384 million (Tab 1, Schedule 2, page 3, line 15, column (n)) which is composed of the following:

- the variance between lost revenues resulting from the audited volumes of 55,611 $10^3 m^3$ and those reflected in rates
- less the lost revenues for 2004 DSM activities (based on 2004 pre-audit volumes of 59,148 $10^3 m^3$) which were approved by the Board for disposition in EB-2006-0057.

The amount of lost revenues related to 2005 is $2.280 million (Tab 1, Schedule 2, page 4, line 16, column (i)). The audit of 2005 DSM volumes is complete and Union is proposing to dispose of the \$2.280 million balance plus interest of \$0.040 million through December 31, 2006 or a total of \$2.320 million (Tab 1, Schedule 2, page 4, line 16, column (l)).

The variance related to 2006 is a debit balance of \$1.421 million (Tab 1, Schedule 2, page 5, line 15, column (d)). The 2006 variance represents 50% of the forecasted volumes savings of 92,274 $10^3 m^3$. No 2006 DSM volume savings are reflected in 2006 rates. The process to finalize DSM balances includes an audit of Union's DSM evaluation report, review by the Audit Sub-Committee and communication to the DSM Consultative. Consistent with the desire of parties to dispose of deferral account balances in a timely manner, Union is proposing to dispose the forecast LRAM balance related to unaudited 2006 DSM activities at this time. The variances between the LRAM balances calculated out of audited and unaudited results have been decreasing, thus increasing Union's confidence in the accuracy of the unaudited numbers. Recognizing this balance may still change following the audit, any amount disposed of would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition.

Account No.179-102 Intra-Period WACOG Changes

The debit balance of \$15.742 million in the Intra-Period WACOG account reflects the difference between the actual WACOG approved by the Board during the year and the WACOG approved for recovery in Union's delivery rates in the RP-2003-0063 proceeding related to inventory carrying costs, compressor fuel, customer supplied fuel and unaccounted for gas. The WACOG approved for recovery in rates was \$310.870 per $10^3 m^3$. The actual WACOG in 2006, approved by the Board in the four QRAM proceedings in 2006, ranged from a low of \$389.207 per $10^3 m^3$ to a high of \$468.942 per $10^3 m^3$.

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

No unauthorized storage overrun charges were incurred by customers electing unbundled service in 2006.

Account No. 179-110 Storage Rights Compensation Costs

The debit balance of \$0.511 million in the Storage Rights Compensation deferral captures the differences between the actual compensation paid for storage rights and the amount included in rates approved by the Board in the RP-2003-0063 proceeding. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No.179-111 Demand Side Management Variance Account

This account records the difference between actual 2006 direct DSM costs incurred and the direct DSM budget included in rates for 2006. The debit balance of \$7.213 million represents the difference between the direct DSM expenditure in 2006 of \$11.182 million and \$4.0 million included in rates, plus interest of \$0.031 million through December 31,

2006. The Board approved direct DSM budget was $12.2 million for 2006 per EB-2005-0507.

Account No. 179-112 Deferred Gas Distribution Access Rule Costs

The Gas Distribution Access Rule ("GDAR") deferral account records the difference between the actual costs incurred to implement the process and system changes needed to achieve compliance with the GDAR and the costs included in rates as approved by the Board. Implementation of the process and system changes for EBT standards and Rate-ready ABC service for large volume customers is required by June 1, 2007. The required implementation date of the bill-ready service component of GDAR is currently January 1, 2008. The Company is continuing to incur costs to comply with the rule. In the EB-2005-0520 proceeding, the Board approved the recovery of an additional $18.2 million of capital in Union's 2007 rates to implement GDAR plus an additional $0.5 million in annual operating expenses. This spending is incremental to the amounts previously approved by the Board and does not include any costs required to be able to offer Vendor Consolidated Billing. The variance between the actual costs incurred and the costs included in rates will be calculated and recorded in the deferral account for disposition in a future proceeding when the project is complete. Disposition of any variance will be proposed in a future proceeding.

Account No. 179-113 Late Payment Penalty Litigation

The debit balance of $0.303 million in the Late Payment Penalty ("LPP") Litigation deferral account is the cost incurred in 2006 by Union in relation to late payment penalty litigation. Amounts include the Company's legal costs, costs of actuarial advice and the cost of analyzing historical billing records.

Account No. 179-114 Incremental OEB Cost Assessment

The debit balance of $1.541 million recorded in the Incremental OEB Cost Assessment account is the difference between the actual payments made in 2006 with respect to OEB cost assessments and the costs included in rates as approved by the Board effective January 1, 2005. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No. 179-115 Shared Savings Mechanism Variance Account

This account has a debit balance of $7.000 million related to DSM activity in 2005 and 2006. Tab 1, Schedule 3 provides the breakdown of the SSM variance account for each year. The account was established to record any shareholder incentive earned by the Company related to DSM activities in 2005 in accordance with the mechanism approved by the Board in the EB-2005-0211 proceeding. The account was continued for DSM activities in 2006 in accordance with the mechanism approved by the Board in the EB-2005-0507 proceeding.

Union has completed the audit of 2005 DSM activity and proposes to dispose of the debit balance of $4.102, which represents an incentive payment of $3.979 million and interest of $0.123 million through December 31, 2006.

This account has a debit balance of $2.898 million related to unaudited 2006 DSM activity. In an effort to recognize the desire of parties to move to a more timely disposition of deferral account balances, Union is proposing to clear the recorded SSM balance related to unaudited 2006 DSM activities. The SSM has been in existence for two years and Union is confident that the tracking process and assessment procedures are in place to produce an accurate calculation of the deferral account balance. Recognizing this balance may still change following the audit, any amount disposed of would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition.

Account No. 179-116 Interest on the Gain on the 2004 Cushion Gas Disposition

The establishment of this deferral account was directed by the Board in its EB-2005-0211 Interim Decision and Order dated June 10, 2005 to record interest on the gain on the 2004 cushion gas disposition starting April 26, 2005. On February 9, 2006, the Supreme Court of Canada released its Decision in the ATCO case. The Supreme Court of Canada found that ratepayers have no property interest in the assets of the utility. Further, the Supreme Court determined that the Alberta Energy and Utilities Board did not have jurisdiction to allocate part of the proceeds to ratepayers. In response to the Supreme Court's decision, the Board reconvened the cushion gas proceeding. In June 2006, the Board released its Decision and Order regarding the cushion gas proceeding. In the decision and subsequent clarification letter, the Board determined that it does not have jurisdiction over the sale of cushion gas sale in accordance with Section 36 of the OEB act. In January 2007, the OEB provided further clarity to the June 2006 Decision. The Board decided that it does not have the jurisdiction to consider the proceeds of the cushion gas sale in setting rates. Furthermore, the Board ordered that "the original panel consider the extent to which, if any, the proceeds from the sale of cushion gas shall be allocated between ratepayers and the utility in light of our findings herein". Union is not proposing to dispose of the balance in this deferral account, pending the review by the original panel.

2. 2006 EARNINGS SHARING

Union's earnings for 2006 continue to be subject to the earnings sharing mechanism implemented by the Board for 2005. Earnings above the benchmark rate of return on equity, normalized for weather, will be shared equally between ratepayers and the Company.

Based on the actual year end results, Union's earnings for 2006 subject to earnings sharing before weather normalization were \$98.023 million, a return on average common equity ("ROE") of 8.59%. Please see Appendix B for a copy of Union's 2006 Annual Report. For 2006, the benchmark ROE was 8.89%. Before normalizing earnings for weather, there is no excess earnings to be shared with ratepayers, as the return to the shareholder was below the benchmark ROE by 0.30% resulting in a utility revenue deficiency of $3.425 million.

In 2006, weather in Union's franchise area was 14% warmer than the heating degree day forecast using the methodology approved by the Board to set rates. Actual heating degree days were 3,605 compared to a forecast of 4,178, a decrease of 573. The forecast methodology for 2006 used the 30-year historical average heating degree days weighted 70% and the 20-year historical trend heating degree days weighted 30%. This methodology was approved by the Board in setting the 2004 rates in the RP-2003-0063 rates proceeding.

The actual heating degrees days in 2006 of 3,605 were 419 heating degree days below the proposed 20 year trend methodology proposed in the 2004 rate case.

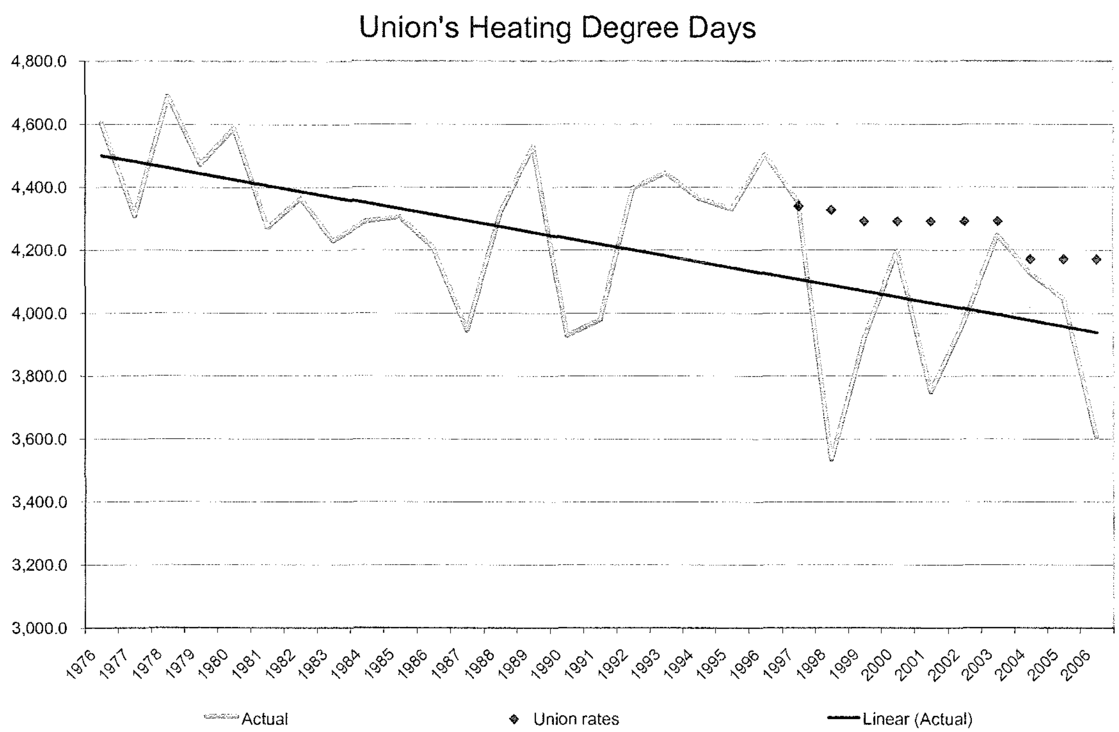
In confirming their decision in RP-2003-0063 in support of using weather normalized earnings in the earnings sharing calculation the Board noted that

> "...The risk of weather has always been borne by the shareholder and, in the absence of a longer term mechanism in place; earnings sharing on the basis of weather normalization is consistent with common regulatory practice and the Board's recent decision in the case of Enbridge."

Union continues to believe that the shareholder risk associated with the Board approved weather normalization methodology is not balanced and the practice of weather normalizing earnings for sharing with the ratepayer produces unacceptable results. In particular, weather normalizing earnings for the purposes of earnings sharing requires the utility to pay earnings to ratepayers that the company in fact never earned.

The graph below shows Union's actual heating degree days from 1976 to 2006, along with the linear regression trend line showing that weather is getting warmer, and the heating degree days underlying Board approved rates. In the past 10 years, 1997 to 2006, Union's shareholder has only experienced actual weather that has been warmer than Board approved (normal) with no opportunity related to colder than normal weather. The result is that Union has had to consistently plan and manage its operations to mitigate the impact of warmer weather on the shareholder. There is, however, no methodology available for normalizing the earnings impact of weather on operating costs or on S&T revenues.

During the same 10-year period, 1997 to 2006, Enbridge Gas Distribution ("EGD"), as reported in Exhibit J4.5 in EB-2006-0034, experienced 3 years where the actual weather was colder that the heating degree days approved by the Board in rates. One of these years, 2004, was the decision referred to by the Board in RP-2003-0063 where EGD's earnings sharing was weather normalized. While the Board has, in its' decision, relied on consistency in the practice of weather normalizing earnings sharing, there is no consistency in how normal weather has been set as evidenced by the fact that for EGD, weather for 7 of 10 years was warmer than normal and for Union, weather for 10 of 10 years was warmer than normal. EGD's shareholder was exposed to less risk than Union's shareholder for the same period as a result of the methodology used for setting normal weather in rates.



In the 2006 earnings sharing calculation the normalization adjustment for the unfavourable variance in distribution margin related to warmer than normal weather is $31.172 million. This adjustment increases earnings by $19.913 million to $117.936 million, resulting in a normalized ROE of 10.33%. Compared to the actual ROE of 8.59%, this adjustment increases shareholder earnings by 1.74% that was not earned by the shareholder. Compared to the benchmark ROE of 8.89%, weather normalized earnings are higher by 1.44%. Paying one half of this hypothetical earnings amount, an amount not realized by the shareholder, to the rate payer ($12.879 million) reduces the actual shareholder earnings for 2006 from 8.59% to 7.87%.

The circumstances presented above illustrate the difficulties with an earnings sharing methodology and point to the need to address the method of weather normalization. Union recognizes the Board's commitment to eliminating earnings sharing mechanisms as part of an incentive regulation framework and its plans to review the weather normalization methodology.

The section below provides a detailed description of the earnings sharing calculation shown at Tab1, Schedule 4:

The starting point for the earnings sharing calculation is Union's actual reported earnings of $98.636 million. The following after-tax adjustments were made to arrive at earnings subject to sharing:

1. Corporate earnings are "grossed-up" by the amount recorded by Union for earnings sharing. This adjustment is necessary in order to arrive at an earnings value prior to earnings sharing.
2. The amount related to the shareholder's portion (10%) of the "base" storage and transportation net revenue is deducted. The base level of storage and transportation revenue as well as 90/10 ratepayer/ shareholder proportional sharing was approved by the Board in the RP-2003-0063 proceeding.
3. The shareholder portion (25%) of the storage and transportation revenue shared in excess of the base level is then deducted.

4. Consistent with the EB-2005-0211 settlement agreement, the amount recorded in the Shared Savings Mechanism Variance Account (Account No. 179-115) is removed from earnings.

5. A non-utility adjustment is then deducted from earnings.

6. Consistent with the Board's EB-2005-0189 decision, earnings are normalized for weather. Union's 2006 weather normalization adjustment is comprised of two parts.

   a) The first part of the adjustment represents the weather related revenue variance associated with the general service market (residential, commercial, small industrial).

   b) The second part of the normalization represents a weather related cost adjustment associated with unaccounted for gas ("UFG") and compressor fuel costs. On a weather normalized basis, consumption would have been lower and Union would have experienced lower compressor fuel and UFG costs. Therefore, the UFG and compressor fuel costs have been added back in order to properly capture the weather related cost effects.

Union is proposing that interest accrue on the earnings sharing amount due to ratepayers at Union's Board-approved short term rate, starting January 1, 2007. This approach is consistent with how the balance would have been treated had a deferral account been established to record the amount.

UNION GAS LIMITED
Deferral Account Balances
Year Ending December 31, 2006
($000's)

Line No.	Account Number	Account Name	Balance (1)
	Gas Supply Accounts:		
	Joint Accounts:		
	179-107	Spot Gas Variance Account	
1		Spot Gas Purchases	$ 12
2		Load Balancing	(6,496)
3	179-108	Unabsorbed Demand Costs	(708)
4	179-109	Inventory revaluations	12,769
5		(Lines 1 through 4)	5,578
	Southern Operations Area:		
6	179-106	PGVA	(145,719)
	Northern and Eastern Operations Area:		
7	179-89	Heating Value	(2,405)
	179-100	TCPL Tolls and Fuel	
8		Tolls, LBA, Capacity Assignments	(445)
9		Fuel	(77)
10	179-105	PGVA	(54,735)
11		(Lines 7 through 10)	(57,662)
12	Total Gas Supply Accounts (Lines 5 + 6 + 11)		(197,803) (2)
	Storage and Transportation Accounts:		
13	179-69	Transportation and Exchange Services	(4,004)
14	179-70	Short Term Storage and Balancing Services	(21,565)
15	179-72	Long-term Peak Storage	9,341
16	179-73	Other S&T Services	(390)
17	179-74	Other Direct Purchase Services	(373)
18	Total Storage and Transportation Accounts (Lines 13 through 17)		(16,990)

UNION GAS LIMITED
Deferral Account Balances
Year Ending December 31, 2006
($000's)

Line No.	Account Number	Account Name	Balance (1)
	Other:		
19	179-26	Deferred Customer Rebates/Charges	-
20	179-56	Comprehensive Customer Information Program	-
21	179-60	Direct Purchase Revenue and Payments	(171)
22	179-75	Lost Revenue Adjustment Mechanism	3,980
23	179-102	Intra-period WACOG Changes	15,742
24	179-103	Unbundled Services Unauthorized Storage Overrun	-
25	179-110	Storage Rights Compensation Costs	511
26	179-111	Demand Side Management Variance Account	7,213
27	179-112	Gas Distribution Access Rule Costs	-
28	179-113	Late Payment Penalty Litigation	303
29	179-114	Incremental OEB Cost Assessment	1,541
30	179-115	Shared Savings Mechanism Variance Account	7,000
31	179-116	Interest on the Gain on the 2004 Cushion Gas Disposition	(896) (3)
32	Total Other Accounts (Lines 19 through 31)		35,224
33	Total Deferral Account Balances (Lines 12 + 18 + 32)		$ (179,570)
34	Total Deferral Account Balances for Recovery/(Refund)		$ 16,016 (4)

Notes:

(1) Account balances include interest to December 31, 2006.

(2) With the exception of UDC (No. 179-108) and Heating Value (No. 179-89) accounts, all gas supply-related deferral account balances are recovered through the QRAM process.

(3) The balance of the Interest on the Gain on the 2004 Cushion Gas Disposition (No. 179-116) will be disposed of in a future proceeding.

(4) Breakdown of the deferral account balances for recovery/(refund):

Total Deferral Account Balances (Line 33)		$ (179,570)
Less Total Gas Supply-related balances recovered through the QRAM process		
Total Gas Supply-related balances (Line 12)	$ (197,803)	
Less: Balance of Unabsorbed Demand Costs Account (No. 179-108) (Line 3)	(708)	
Balance of Heating Value Account (No. 179-89) (Line 7)	(2,405)	(194,690)
Net Amount		15,121
Less: Balance of the Interest on the Gain on the 2004 Cushion Gas Disposition Account (No. 179-116) (Line 31).		(896)
Total Amount for Recovery/(Refund)		$ 16,016

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
Breakdown of 2006 LRAM Deferral Account Balance

Line No.	Particulars	2003 (1)	2004 (2)	2005 (3)	2006 (4)	Total Amount in LRAM Deferral Account
		Amounts by DSM Plan Year				
		(a)	(b)	(c)	(d)	(e)
	South					
1	M2 Residential	$35,981	$100,981	$376,190	$387,335	$900,487
2	M2 Commercial	($353,409)	$9,388	$897,125	$477,616	$1,030,721
3	M2 Industrial	$0		$74,100	$31,199	$105,299
	Industrial					
4	M4	$23,421	$21,054	$161,548	$56,779	$262,801
5	M5	$0	$64,466	$0	$0	$64,466
6	M7	$8,291	($5,917)	$20,468	$3,524	$26,366
7	T1	($10,342)	($3,298)	$9,476	$7,779	$3,616
8		($296,058)	$186,674	$1,538,907	$964,232	$2,393,756
	North					
9	Residential 01	$121,376	$62,107	$230,716	$139,286	$553,485
10	Commercial 01	$57,632	$5,841	$214,739	$237,362	$515,574
11	Commercial 10	($27,022)	$108,779	$214,771	$47,727	$344,255
12	Industrial 10	$0	$0	$56,210	$17,784	$73,995
	Industrial					
13	Rate 20	$246	$3,799	$43,994	$2,382	$50,422
14	Rate 100	($1,610)	$17,071	$21,151	$12,117	$48,729
15		$150,621	$197,596	$781,582	$456,659	$1,586,459
16	Total	($145,436)	$384,270	$2,320,489	$1,420,892	$3,980,215

Notes:

(1) EB-2007-0598, Exhibit A, Tab 1, Schedule 2, page 2 of 5, column (n)
(2) EB-2007-0598, Exhibit A, Tab 1, Schedule 2, page 3 of 5, column (n)
(3) EB-2007-0598, Exhibit A, Tab 1, Schedule 2, page 4 of 5, column (l)
(4) EB-2007-0598, Exhibit A, Tab 1, Schedule 2, page 5 of 5, column (d)

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2003 Actual - Audited

Line No.	Particulars	Audited Volumes [1] $10^3 m^3$	2003 Lost Revenues in 2004 Rates [2] ($)	Delivery Rates: 2004 Rates $\$/10^3 m^3$	Delivery Rates: 2005 Rates $\$/10^3 m^3$	Delivery Rates: 2006 Rates $\$/10^3 m^3$	Lost Revenues: 2004 ($)	Lost Revenues: 2005 ($)	Lost Revenues: 2006 ($)	Net Revenue Impact: 2004 [3] ($)	Net Revenue Impact: 2005 ($)	Net Revenue Impact: 2006 ($)	Net Revenue Impact: Total ($)	LRAM Deferral Account Balance Disposed of in EB-2006-0057 [3] ($)	Net LRAM Deferral Account Balance Proposed for Disposition ($)
		(a)	(b)	(c)	(d)	(e)	(f) = (a) x (c)	(g) = (a) x (d)	(h) = (a) x (c)	(i) = (f) - (b)	(j) = (g) - (b)	(k) = (h) - (b)	(l) = (a) + (b)+ (c)	(m)	(n) = (l) - (m)
	South														
1	M2 Residential	7,220	441,680	74.196	67.316	66.158	535,695	486,022	477,661	94,015	44,342	35,981	174,338	138,357	35,981
2	M2 Commercial	9,104	808,691	56.479	51.167	50.009	514,185	465,824	455,282	(294,506)	(342,866)	(353,409)	(990,781)	(637,372)	(353,409)
	Industrial														
3	M4	3,262	2,554	9.419	8.692	7.963	30,725	28,353	25,975	28,170	25,799	23,421	77,390	53,969	23,421
4	M5			17.525	15.777	15.399	-	-	-	-	-	-	-	-	-
5	M7	3,027	-	3.491	3.115	2.739	10,567	9,429	8,291	10,567	9,429	8,291	28,287	19,996	8,291
6	T1	3,233	12,873	1.240	1.011	0.783	4,009	3,269	2,531	(8,864)	(9,604)	(10,342)	(28,810)	(18,469)	(10,342)
7		25,846	1,265,798				1,095,181	992,897	969,740	(170,617)	(272,901)	(296,058)	(739,576)	(443,518)	(296,058)
8	North														
9	Residential 01	5,239	457,597	102.411	111.186	111.186	536,531	582,503	582,503	78,934	124,907	124,907	328,748	207,372	121,376
10	Commercial 01	549	-	88.061	104.976	104.976	48,345	57,632	57,632	48,345	57,632	57,632	163,609	105,977	57,632
11	Commercial 10	1,080	97,028	55.711	64.820	64.820	60,168	70,006	70,006	(36,860)	(27,022)	(27,022)	(90,904)	(63,882)	(27,022)
	Industrial														
12	Rate 20	93	-	2.645	2.647	2.647	246	246	246	246	246	246	738	492	246
13	Rate 100	6,053	13,613	1.983	1.983	1.983	12,003	12,003	12,003	(1,610)	(1,610)	(1,610)	(4,830)	(3,220)	(1,610)
14		13,014	568,238				657,294	722,390	722,390	89,056	154,153	154,153	397,361	246,740	150,621
15	Total	38,860	1,834,036				1,752,475	1,715,287	1,692,131	(81,561)	(118,749)	(141,905)	(342,215)	(196,778)	(145,436)

Notes:
(1) EB-2006-0057 Exhibit A, Tab 1, Schedule 2, Page 2 of 4, Col. (e)
(2) EB-2006-0057 Exhibit A, Tab 1, Schedule 2, Page 2 of 4, Col. (c)
(3) EB-2006-0057 Exhibit A, Tab 1, Schedule 2, Page 2 of 4, Cols. (l) + (m).

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2004 Actual - Audited

Line No.	Particulars	Audited Volumes (1) $10^3 m^3$	2004 Lost Revenues in Rates (2) ($)	Delivery Rates: 2004 Rates $\$/10^3 m^3$	Delivery Rates: 2005 Rates $\$/10^3 m^3$	Delivery Rates: 2006 Rates $\$/10^3 m^3$	Lost Revenues: 2004 (3) ($)	Lost Revenues: 2005 ($)	Lost Revenues: 2006 ($)	Net Revenue Impact: 2004 ($)	Net Revenue Impact: 2005 ($)	Net Revenue Impact: 2006 ($)	Net Revenue Impact: Total ($)	LRAM Deferral Account Balance Recovered of in EB-2006-0057 (4) ($)	Net LRAM Deferral Account Balance Proposed for Disposition ($)
		(a)	(b)	(c)	(d)	(e)	(f) = (a) x 50% x (c)	(g) = (a) x (d)	(h) = (a) x (e)	(i) = (f) - (b)	(j) = (g) - (b)	(k) = (h) - (b)	(l) = (i) + (j) + (k)	(m)	(n) = (l) - (m)
	South														
1	M2 Residential	3,904	123,054	74.196	67.316	66.158	144,839	262,816	258,295	21,784	139,762	135,241	296,787	195,806	100,981
2	M2 Commercial	12,743	394,929	56.479	51.167	50.009	359,862	652,032	637,275	(35,067)	257,103	242,346	464,381	454,993	9,388
	Industrial		-				-	-	-	-	-	-		-	
3	M4	4,135	11,877	9.419	8.692	7.963	19,476	35,946	32,931	7,599	24,068	21,053	52,720	31,667	21,054
4	M5	5,200	17,472	17.525	15.777	15.399	45,569	82,047	80,081	28,096	64,574	62,609	155,279	90,813	64,466
5	M7	-	5,917	3.491	3.115	2.739	-	-	-	(5,917)	(5,917)	(5,917)	(17,752)	(11,834)	(5,917)
6	T1	9,061	10,392	1.240	1.011	0.783	5,618	9,161	7,095	(4,774)	(1,231)	(3,297)	(9,303)	(6,006)	(3,298)
7		35,045	563,643				575,363	1,042,001	1,015,677	11,720	478,358	452,034	942,112	755,439	186,674
			-												
8	North		-												
9	Residential 01	1,121	49,208	102.411	111.186	111.186	57,400	124,635	124,635	8,191	75,427	75,427	159,045	96,938	62,107
10	Commercial 01	674	62,743	88.061	104.976	104.976	29,669	70,736	70,736	(33,074)	7,992	7,992	(17,090)	(22,931)	5,841
11	Commercial 10	2,583	41,560	55.711	64.820	64.820	71,939	167,402	167,402	30,378	125,841	125,841	282,060	173,282	108,779
			-				-	-	-	-	-	-		-	-
	Industrial		-				-	-	-	-	-	-		-	-
12	Rate 20	2,522	2,876	2.645	2.647	2.647	3,335	6,675	6,675	459	3,799	3,799	8,056	4,257	3,799
13	Rate 100	13,667	10,031	1.983	1.983	1.983	13,551	27,102	27,102	3,520	17,071	17,071	37,662	20,591	17,071
14		20,566	166,420				175,893	396,550	396,550	9,473	230,130	230,130	469,733	272,137	197,596
15	Total	55,611	730,063				751,256	1,438,551	1,412,227	21,193	708,488	682,164	1,411,846	1,027,575	384,270

Notes:
(1) EB-2-006-0021, Exhibit JT 2.27, Attachment 2 (Summary of the the Results of the 2004 Evaluation Report Audit), page 5.
(2) EB-2006-0057 Exhibit A, Tab 1, Schedule 2, Page 3 of 4, Col. (c). The amount is based on total volumes of 59,148 $10^3 m^3$.
(3) The 50% factor is in accordance with the Board's ruling in RP-2001-0029 Decision with Reasons at paragraph 2.171 which requires that 50% of volume savings should be reflected in the first year in which the DSM measure is undertaken.
(2) EB-2006-0057 Exhibit A, Tab 1, Schedule 2, Page 3 of 4, Cols.(i) + (j).

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2005 Actual - Audited

				Delivery Rates		Lost Revenues		Net Revenue Impact					
Line No.	Particulars	Audited Volumes [1] $10^3 m^3$	2005 Lost Revenues in Rates [2] ($)	2005 Rates $\$/10^3 m^3$	2006 Rates $\$/10^3 m^3$	2005 [3] 50%	2006	2005 ($)	2006	Total ($)	LRAM Deferral Account Balance Disposed of in EB-2006-0057 [4] ($)	Interest ($)	Net LRAM Deferral Account Balance Proposed for Disposition Including Interest ($)
		(a)	(b)	(c)	(d)	(e) = (a) x 50% x (c)	(f) = (a) x (d)	(g) = (e - (b)	(h) = (f) - (b)	(i) = (g + (h)	(j)	(k)	(l) = (i) - (j) +(k)
	South												
1	M2 Residential	3,703	-	67.316	66.158	124,643	244,998	124,643	244,998	369,641	-	6,550	376,190
2	M2 Commercial	11,661	-	51.167	50.009	298,337	583,169	298,337	583,169	881,506	-	15,619	897,125
3	M2 Industrial	1,262		39.246	38.088	24,757	48,053	24,757	48,053	72,810		1,290	74,100
	Industrial												
4	M4	12,896	-	8.692	7.963	56,046	102,690	56,046	102,690	158,735	-	2,813	161,548
5	M5	-	-			-	-	-	-	-	-	-	-
6	M7	4,681	-	3.115	2.739	7,291	12,821	7,291	12,821	20,111	-	356	20,468
7	T1	7,227	-	1.011	0.783	3,653	5,658	3,653	5,658	9,311	-	165	9,476
8		41,429	-			514,726	997,389	514,726	997,389	1,512,115		26,793	1,538,907
	North												
9	Residential 01	1,359	-	111.186	111.186	75,567	151,133	75,567	151,133	226,700	-	4,017	230,716
10	Commercial 01	1,340	-	104.976	104.976	70,334	140,667	70,334	140,667	211,001	-	3,739	214,739
11	Commercial 10	2,170	-	64.820	64.820	70,344	140,688	70,344	140,688	211,032	-	3,739	214,771
12	Industrial 10	621		59.311	59.311	18,411	36,821	18,411	36,821	55,232	-	979	56,210
						-							
	Industrial					-							
13	Rate 20	10,887	-	2.647	2.647	14,410	28,819	14,410	28,819	43,229	-	766	43,994
14	Rate 100	6,987	-	1.983	1.983	6,928	13,855	6,928	13,855	20,783		368	21,151
15		23,365	-			255,992	511,983	255,992	511,983	767,975	-	13,607	781,582
16	Total	64,794	-			770,717	1,509,372	770,717	1,509,372	2,280,089	-	40,400	2,320,489

Notes:

(1) Summary of the Results of the 2005 Evaluation Report Audit, page 4 (submitted by Union to the OEB Secretary on December 28, 2006 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements).

(2) 2005 rates did not reflect forecast volumes lost due to DSM activities.

(3) The 50% factor is in accordance with the Board's ruling in RP-2001-0029 Decision with Reasons at paragraph 2.171 which requires that 50% of volume savings should be reflected in the first year in which the DSM measure is undertaken.

(4) Union did not propose the disposition of lost revenues due to 2005 DSM activities as stated in EB-2006-0057 Exhibit A, Tab 1, Page 9.

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2006 Forecast

Line No.	Particulars	Annualized Impact: Net Volume Savings [1] $10^3 m^3$	2006 Delivery Rates [2] $\$/10^3 m^3$	Total Revenue Impact ($)	Impact for 2006 Revenues ($)
		(a)	(b)	(c) = (a) x (b)	(d) = (c) x 50% [2]
	South				
1	M2 Residential	11,709	66.158	774,670	387,335
2	M2 Commercial	19,101	50.009	955,233	477,616
3	M2 Industrial	1,638	38.088	62,398	31,199
	Industrial				
4	M4	14,261	7.963	113,558	56,779
5	M7	2,573	2.739	7,049	3,524
6	T1	19,870	0.783	15,558	7,779
7		69,153		1,928,465	964,232
	North				
8	Residential 01	2,505	111.186	278,572	139,286
9	Commercial 01	4,522	104.976	474,724	237,362
10	Commercial 10	1,473	64.820	95,454	47,727
11	Industrial 10	600	59.311	35,569	17,784
	Industrial				
12	Rate 20	1,800	2.647	4,765	2,382
13	Rate 100	12,221	1.983	24,234	12,117
14		23,121		913,319	456,659
15	Total	92,274		2,841,783	1,420,892

Notes:

(1) Based on unaudited 2006 DSM revaluation results

(2) The Year One Impact net volume savings are based on the Board's ruling in RP-2001-0029 Decision with Reasons at paragraph 2.170 that 50% savings should be reflected in the first year in which the DSM measure is undertaken.

UNION GAS LIMITED
Shared Savings Mechanism Variance Account
2005 Audited and 2006 Unaudited Results

Line No.	Particulars	SSM Incentives: 2005 Amount: 2005 Amount [(1)] ($)	2005 Amount: Interest ($)	Total for 2005 ($)	2006 Amount [(2)] ($)	Total for 2005 and 2006 ($)
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	South					
1	M2 Residential	143,432	4,514	147,947	419,123	567,070
2	M2 Commercial	1,197,199	37,681	1,234,880 .	635,383	1,870,263
3	M2 Industrial	26,405	831	27,237	44,309	71,546
4	Industrial					
5	M4	550,462	14,796	565,258	440,792	1,006,051
6	M7	300,582	9,461	310,042	65,927	375,970
7	T1	276,220	8,694	284,914	614,467	899,381
8		2,494,300	75,978	2,570,278	2,220,003	4,790,280
	North					
9	Residential 01	91,501	2,880	94,381	96,446	190,827
10	Commercial 01	123,380	3,883	127,264	150,093	277,356
11	Commercial 10	328,946	10,353	339,299	37,409	376,708
12	Industrial 10	9,295	293	9,587	14,316	23,903
	Industrial					
13	Rate 20	595,436	18,741	614,177	57,818	671,995
14	Rate 100	336,204	10,582	346,786	321,887	668,673
15		1,484,762	46,732	1,531,494	677,968	2,209,463
16	Total	3,979,062	122,710	4,101,772	2,897,971	6,999,743

Notes:

(1) 2005 audited amount of SSM incentives calculated using the mechanism approved by the Board in EB-2005-0211. The allocation of the amount is based on 2005 TRC results achieved by rate class.

(2) 2006 unaudited amount of SSM incentives calculated using the mechanism approved by the Board in EB-2005-0507. The allocation of the amount is based on 2006 TRC results achieved by rate class.

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ending December 31, 2006

Line No.	Particulars ($000's)		Calendar 2006 (a)
1	Corporate earnings	$	98,636
	Adjustments required for Earnings Sharing (net of tax):		
2	Add back provision for earnings sharing		8,521
3	S&T base revenue - shareholder portion (10%)		(1,655)
4	S&T revenue in excess of base - shareholder portion (25%)		(3,846)
5	Shared savings mechanism incentive (SSM)[1]		(2,356)
6	Other non-utility adjustment		(1,278)
7	Earnings subject to sharing before weather normalization (lines 1 through 6)		98,023
8	Weather normalization [3]		19,913
9	Earnings subject to sharing (lines 7 + 8)	$	117,936
10	Average corporate common equity	$	1,141,528
11	ROE used for earnings sharing (line 9 / line 10)		10.33%
12	Benchmark ROE [2]		8.89%
13	Earnings sharing % (line 11 minus line 12)		1.44%
14	Earnings sharing amount (line 13 x line 10 / 2)	$	8,226.9
15	Pre-tax earnings sharing amount (line 14 / (1 minus tax rate))	$	12,879

Notes:
1 SSM excluded from earnings sharing per EB-2005-0211 settlement agreement
2 Based on October 2005 consensus forecast
3 The weather normalization amount was calculated as follows:

General Service Market	$	33,317
UFG/Fuel costs		2,145
Total Pre-tax		31,172
Income Tax		11,259
Total After-tax	$	19,913

ERNST & YOUNG

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April 27, 2007

Ms. Pat Elliott
Director Accounting and Internal Controls
Union Gas - a Spectra Energy Company
50 Keil Drive North
P.O.Box 2001
Chatham, ON N7M 5M1

Dear Ms. Elliott:

You have requested that Ernst & Young LLP provide an opinion on the accounting impact on future income taxes as a result of the Ontario Energy Board's ("Board" or "OEB") 2006 decision to forebear from regulatory oversight a portion of Union Gas' ("Union" or the "Company") gas storage operations. You have informed us that this letter will be used as evidence in support of the planned disposition of the 2006 deferred account balances.

THE ACCOUNTING ISSUE

What are the accounting impacts on future income taxes when an entity or certain operations of an entity no longer meet the definitions of being a "rate regulated entity"?

SUMMARY OF RELEVANT FACTS

In December 2005, the OEB commenced a proceeding to determine whether to refrain, in whole or part, to continue to regulate the rates charged for the storage of natural gas in Ontario. In Union's submission, it indicated that the Board should forbear from regulating the prices for its storage services to customers outside of Union Gas' franchise area.

On November 7, 2006, the OEB released its Decision with Reasons with respect to the "Natural Gas Electricity Interface Review – EB – 2005-0551" ("NGEIR"). A key issue addressed in the proceeding was natural gas storage regulation. The issue in this hearing was whether the OEB should cease its "regulation" of the prices charged for storage services. As documented in this report:

> **"Price Regulation**
>
> The Board will cease regulating the prices charged for the following storage services:
>
> - all storage services offered by Union and Enbridge to customers outside their franchise areas;
> - new storage services offered by Union and Enbridge to their in-franchise customers; and,
> - all storage services offered by other storage operators, including storage operators affiliated with Union and Enbridge.

Rates for storage services provided to Union's and Enbridge's distribution customers will continue to be regulated by the Board of a cost-of-service basis.

Union's existing storage capacity is well in excess of the current needs of its in-franchise customers and has been for many years. The Board has decided that Union will reserve approximately two-thirds of its existing capacity for in-franchise needs. At current rates of growth, that amount limit will satisfy in-franchise needs for several decades. Enbridge currently purchases storage from Union for a portion of its requirements. The Board has decided that Union will continue to provide these services at cost through a transition period ending in 2010."

The prices currently charged by Union for storage services generally depend on whether the customer is "in-franchise" or "ex-franchise" and the Board regulates the pricing for these services. The ex-franchise customers pay market-based prices whereas the in-franchise customers pay cost-based rates. The Board has directed that most of the premium of the market-based prices for storage services be credited against the distribution rates. Prior to the decision the gas storage operations met the definition of being a "rate regulated entity".

As a result of the Decision, Union Gas' is of the opinion that the above mentioned natural gas storage operations are no longer subject to price regulation and therefore do not meet the definition of a rate regulated entity, as discussed in CICA Handbook Section 1100.

Union has stated that since 1997, the Company's income tax expense was recorded using the flow through tax accounting methodology. Under Canadian GAAP, rate-regulated entities are not required to record deferred (future) income tax expenses to the extent that these costs are expected to be recovered from customers in future rates.

ACCOUNTING DISCUSSION

Under Canadian generally accepted accounting principles ("Canadian GAAP") rate-regulated entities are not presently required to apply Section 1100 for the recognition and measurement of assets and liabilities arising from rate regulation.

Rate regulation exists when all of the following criteria are present (per CICA Handbook Section 1100.36):

a) The rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products.

b) The regulated rates are designed to recover the cost of providing the services or products.

c) It is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition.

Section 3465 of the Canadian Institute Chartered Accountants Handbook provides guidance for accounting for income taxes for rate regulated entities as follows:

RATE-REGULATED ENTERPRISES

Paragraph .102 A rate-regulated enterprise need not recognize future income taxes in accordance with this Section to the extent that future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers.

Paragraph .104 Future income taxes would be recognized in accordance with the remainder of this Section to the extent that future income taxes are not expected to be included in the rates charged to customers in the future.

In situations where the primary sources of Canadian GAAP do not deal with certain events or transactions an entity should seek other guidance, including accounting pronouncements published with the authority of the US Financial Accounting Standards Boards (FASB). Therefore, we refer to U.S. GAAP to assist in identifying appropriate accounting guidance when there has been a change in the circumstances for a rate regulated entity as there is no specific Canadian GAAP guidance on this topic.

FAS 101-Regulated Enterprises- Accounting for the Discontinuation of Application of FASB Statement No.71 specifies the accounting for an enterprise that ceases to meet the criteria for the application of *FAS No.71- Accounting for the Effects of Certain Types of Regulation*. The Statement specifically states:

"An enterprise's operations can cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation, or a change in the competitive environment for the enterprise's regulated services or products. Regardless of the reason, an enterprise whose operations cease to meet those criteria should discontinue application of that Statement and report that discontinuation by eliminating from its statement of financial position the effects of any actions of regulators that had been recognized as assets and liabilities pursuant to Statement 71 but would not have been recognized as assets and liabilities by enterprises in general. However, the carrying amounts of plant, equipment, and inventory measured and reported pursuant to Statement 71 should not be adjusted unless those assets are impaired, in which case the carrying amounts of those assets should be reduced to reflect that impairment. The net effect of the adjustments should be included in income of the period of the change and classified as an extraordinary item."

Specific examples listed in FAS 101 where the criteria for regulatory accounting are no longer met include:

a) Deregulation

b) A change in the regulator's approach to setting rates from cost-based rate making to another form of regulation.

ERNST & YOUNG

The criteria defining a rate regulated entity per FAS #71 is similar to those specified in Canadian GAAP.

FAS statement 101 specifically states:

> "Paragraph 5. When an enterprise determines that its operations in a regulatory jurisdiction no longer meet the criteria for application of Statement 71, that enterprise shall discontinue application of that Statement to its operations in that jurisdiction. If a separable portion of the enterprise's operations within a regulatory jurisdiction ceases to meet the criteria for application of Statement 71, application of that Statement to that separable portion shall be discontinued. That situation creates a presumption that application of Statement 71 shall be discontinued for all of the enterprise's operations within that regulatory jurisdiction. That presumption can be overcome by establishing that the enterprise's other operations within that jurisdiction continue to meet the criteria for application of Statement 71."

CONCLUSION

The Board has indicated in its decision (NGEIR page 74) to cease regulating the prices for "ex-franchise" customers and concluded that "Union's current cost allocation study is adequate for the purposes of separating the regulated and unregulated costs and revenues for ratemaking purposes." (NGEIR page 74) Based upon this decision Union should separate the storage operations between regulated and unregulated operations and can therefore overcome the presumption that the rate regulation relates to the entire gas storage operations. Assuming that the particular component of the storage operations no longer meet the criteria of rate regulation, FAS 101 indicates that when this criterion is no longer met, the entity should discontinue the application of Statement 71. As a result of discontinuation of Statement 71, the Company is required to change its accounting for future income taxes and accordingly provide for future income taxes on temporary differences. The change in accounting should be applied in the period the criteria for regulatory accounting were no longer met. The effect of the change in earnings would be recorded as an extraordinary item.

Our conclusion is based on the facts summarized above. Changes to these facts could cause our conclusion to change. This letter is intended solely for the information and use of management, and is not intended to be and should not be used or relied on by any other parties.

Yours truly,

Ernst + Young LLP

Chartered Accountants
Licensed Public Accountants

Deloitte.

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April 13, 2007

Private and confidential

Ms. Pat Elliott
Director Accounting and Internal Controls
Union Gas Limited
P.O. Box 2001
50 Keil Drive North,
Chatham, ON N7M 5M1

Dear Ms. Elliott:

Please be advised that Rule 204.4, Specific Prohibitions, Assurance and Specified Auditing Procedures Engagements, paragraph (29) deals specifically with the situation where an Auditor is requested to provide expert witness testimony to a listed entity audit client. It states:

> (29) A member or Firm shall not perform an audit engagement for a listed entity if, during either the period covered by the financial statements subject to audit or the engagement period, the member, the firm, a network firm or a member of the firm or network firm, provides an expert opinion or other expert service for the entity or a related entity, or for a legal representative thereof, for the purpose of advocating the entity's or related entity's interest in a civil, criminal, regulatory, administrative or legislative proceeding or investigation.

Accordingly, since Deloitte & Touche are the auditors of Union Gas Limited, the provision of these services would constitute a breach of the Rules of Professional Conduct.

Yours very truly,

Mark Morrison

Mark Morrison, CA, Licensed Public Accountant
Partner, Assurance & Advisory
Deloitte & Touche LLP

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ANNUAL REPORT 2006

EB-2007-0598
Exhibit A
Tab 1
Appendix B

uniongas
A Spectra Energy Company

unionpgas
A Spectra Energy Company

Julie Dill
President

March 23, 2007

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited ("Union") 2006 annual report. It contains Union's financial results, balance sheet and income statement, management's discussion and analysis, statement of corporate governance and corporate directory. I invite you to visit www.sedar.com for electronic versions of Union's financial statements, management's discussion and analysis, and other filings throughout the year.

Julie Dill

This discussion and analysis of Union Gas Limited (the "Company" or "Union") for the twelve months ended December 31, 2006, should be read in conjunction with the annual financial statements and accompanying notes. The results reported herein have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in millions of Canadian dollars except where noted. Additional information relating to the Company, including the Company's latest Annual Information Form, can be found at www.sedar.com.

FORWARD LOOKING INFORMATION

The information set out herein contains forward-looking statements with respect to the Company. By their nature, these forward-looking statements involve risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions, the ability of the Company to successfully implement the initiatives and projects referred to, natural gas prices, availability of capital, changes in the regulatory environment in which the Company operates (including changes in allowed rates of return), and changes in the laws and government regulations applicable to the Company.

Any forward looking statement speaks only as of the date on which it is made and the Company undertakes no obligation to update any forward looking statement or statements to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for the Company to predict which will arise after the date of the annual report.

GENERAL

Union was originally incorporated under the laws of the Province of Ontario by letters patent dated December 19, 1911. Prior to January 2, 2007, the Company was an indirect wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy"). On January 2, 2007, Duke Energy created two separate publicly traded companies by spinning off Duke Energy's natural gas business to Duke Energy shareholders. The new natural gas company, Spectra Energy Corp, consists of Duke Energy's former Natural Gas Transmission business segment, which includes the Company. The decision to spin off the natural gas business is expected to deliver long-term value to shareholders as the stand-alone companies will be able to more easily participate in growth opportunities in their own industries as well as the gas and power industry consolidations.

Union is a Canadian natural gas utility, regulated by the Ontario Energy Board ("OEB") and provides natural gas distribution, transmission, storage and related services to approximately 1.3 million residential, commercial and industrial customers in over 400 communities in northern, southwestern and eastern Ontario. Its distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. The Company also provides natural gas storage and transmission services for other utilities and customers located outside of the Company's distribution service area.

HIGHLIGHTS

	For the Years ended December 31		
($millions except where noted)	**2006**	2005	2004
Income			
Total operating revenues	**2,079**	2,084	1,841
Earnings applicable to common shares	**99**	116	147
Dividends			
Dividends on preference shares	**5**	5	5
Dividends on common shares	**49**	115	125
Assets and long-term financial liabilities			
Total assets	**4,560**	4,126	3,961
Total long-term financial liabilities	**2,315**	2,169	2,029
Volumes of gas (10^6m^3)[1]			
Distribution volumes	**13,207**	14,198	14,450
Transportation volumes	**20,603**	23,732	21,968
Total throughput	**33,810**	37,930	36,418
Customers *(thousands)*	**1,268**	1,249	1,224
Heating degree days[2] *(degree Celsius)*			
Actual	**3,605**	4,041	4,146
Normal[3]	**4,178**	4,182	4,171

[1] *10^6m^3 equals millions of cubic meters. One cubic meter is equivalent to 35.31467 cubic feet.*

[2] *A heating degree day is a measure of temperature that identifies the need for heating. A degree day occurs when the temperature dips below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 heating degree days.*

[3] *As per OEB approved methodology used in setting rates.*

OPERATING RESULTS

	For the Years ended December 31		
($millions)	**2006**	2005	2004
Gas sales and distribution revenue	**1,855**	1,876	1,635
Cost of gas	**1,249**	1,237	986
Gas distribution margin	**606**	639	649
Storage and transportation revenue	**191**	172	171
Other revenue	**33**	36	35
Expenses	**536**	521	511
Other income	**2**	1	12
Interest expense	**155**	156	164
Income taxes	**37**	50	40
Net income	**104**	121	152
Earnings applicable to common shares	**99**	116	147

Gas Distribution Margin

Revenue and cost of gas from gas sales and distribution services is recorded on the basis of regular meter readings and estimates of the unbilled customer usage. The unbilled estimate covers the period of the last meter reading date to the end of each month and is calculated using the number of days unbilled, heating degree-days ("HDD") and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2006 and 2005 was $115 million and $149 million, respectively.

The gas distribution margin decreased $33 million in 2006 as compared to 2005 primarily due to warmer weather. 2006 was an unusually warm year experiencing 436 fewer HDD than 2005 and 573 fewer HDD days compared to normal.

In 2005 the gas distribution margin decreased $10 million as compared to 2004 due to:

- unfavourable gas measurement differences resulting from: higher unaccounted for volumes ($8 million), the increased cost of gas ($7 million) and the discontinuation of deferring gas measurement differences ($10 million);
- 2005 earnings sharing provision that was not in effect during 2004; and
- a decrease in usage;
- these unfavourable variances were partially offset by favourable other margin variances, which is an accumulation of several individual less significant variances, customer growth, lower system operating costs, and a revised methodology for the estimate of the monthly fixed customer charge.

Storage and Transportation Revenue

Storage and transportation customers are primarily Canadian natural gas transmission and distribution companies. Approximately 94% of the Company's annual storage and transportation revenue is generated by fixed demand charges under contracts with remaining terms of up to 16 years and an average outstanding term of 5 years.

Storage and transportation net revenue increased by $19 million compared to 2005 primarily due to recovery of additional deferred tax charges incurred during 2006 (see Income Tax discussion below). The remaining increase is primarily due to an increase in natural gas storage prices driven by warmer weather, offset by a marginal decrease in transportation revenues.

Expenses

Expenses include operating and maintenance expenses, depreciation and amortization, and property and capital taxes.

Expenses were $15 million higher in 2006 as compared to 2005 consisting of:

- $7 million higher operating and maintenance costs primarily due to higher salary and wage costs and pension and post retirement benefit costs. In large part pension and post retirement benefit expenses are based on long-term bond yields. A decline in bond yields has resulted in increased pension and post retirement benefit expense. This is due to the use of a lower discount rate to calculate the present value of the pension and post retirement benefit costs. These higher costs were partially offset by lower bad debt costs.

- $7 million higher depreciation costs due to a net increase in capital assets.

Expenses were $10 million higher in 2005 as compared to 2004 consisting of:

- $3 million higher operating and maintenance costs in 2005 primarily due to higher pension and post retirement benefit costs, salary and wage costs in 2005, partially offset by lower regulatory hearing costs. The higher pension and post retirement benefit cost is due to use of a lower discount rate to calculate the present value of the pension and post retirement benefit costs.

- Depreciation costs increased $4 million in 2005 due to a net increase in capital assets.

Other Income

Other income decreased $11 million in 2005 as compared with 2004. In 2004 the Company recognized a gain of $13 million on the sale of base pressure gas and a loss of $1 million on the sale of the corporate aircraft. The base pressure gas sale is currently the subject of a regulatory review by the OEB.

Income Taxes

The Company records income taxes for its regulated operations using the flow through tax accounting methodology as approved by the OEB. Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Generally, rates and revenues for regulated utility operations include recovery of only such income taxes as are currently payable. Accordingly, except for the items in the next paragraph, the Company does not provide for deferred income taxes.

Deferred income tax is calculated on temporary differences between the approved cost and the actual cost of gas and on temporary differences arising on certain employee future benefits deferred in accounts.

On November 7, 2006 the Company received a decision from the OEB concluding that the OEB will not regulate the prices of storage services to customers outside of Union's franchise area or the prices of new storage services to customers within its franchise area. This decision has created a further exception to the use of flow through tax accounting noted above. During the fourth quarter of 2006, the Company recorded a $10 million charge to income for deferred income taxes related to those storage operations that are no longer subject to regulation. The charge represents the deferred income tax that would have been recorded up to and including 2006 had the Company been subject to normalized income taxes on those storage operations. The amount is offset by higher storage revenues. The Company will continue to record deferred income taxes on these assets in future years.

Prior to 1997, the Company utilized the tax allocation method to account for income taxes. Under this method, provision was made for income taxes deferred principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the accounts. As approved by the OEB, this balance is reduced as the timing differences that gave rise to these deferred income taxes reverse. The timing differences are expected to fully reverse by 2018.

The effective tax rate was 26.2% in 2006 and 29.4% in 2005. The decrease in the effective rate was primarily due to the elimination of the Large Corporations Tax in 2006 and a difference in deductions claimed for income tax purposes compared to amounts recorded for accounting purposes. These items are mitigated by the recognition of a long-term deferred tax liability related to gas storage.

QUARTERLY RESULTS

($millions)	Q1 2005	Q2 2005	Q3 2005	Q4 2005	Q1 2006	Q2 2006	Q3 2006	Q4 2006
Gas sales and distribution revenue	772	286	247	571	834	304	196	521
Storage and transportation revenue	44	41	43	44	46	46	44	55
Other revenue	8	9	8	11	8	7	7	11
Total operating revenues	824	336	298	626	888	357	247	587
Net income (loss)	83	6	(10)	42	75	5	(10)	34
Net earnings (loss) applicable to common shares	82	4	(11)	41	74	3	(11)	33

Seasonal Trends

The natural gas distribution business is highly seasonal due to volume-based rates and the significant effect of the winter heating season on volumes. This is typically reflected in strong first quarter results, second and third quarters that show either small profits or losses and strong fourth quarter results, subject to the impact of warmer than normal temperatures on demand during the winter heating season. Changes in natural gas prices that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in revenue are completely offset in the cost of gas, resulting in no impact to net income.

Significant variances in net income/(loss) for the most recent four quarters as compared to the same reporting period a year earlier are outlined in the following table.

		Favourable/(Unfavourable)					
		---- Quarter ----				----YTD ----	
($millions)		Q1	Q2	Q3	Q4	Dec	Dec
Net income (loss) for the period ended:	**2004**						**152**
	2005	**83**	**6**	**(10)**	**42**	**121**	
Variances:							
Gas distribution margin:							
Earnings sharing		11	–	(5)	(8)	(2)	(11)
Usage per customer		(5)	–	(3)	3	(5)	(10)
Customer growth		4	3	1	1	9	9
Weather		(18)	(4)	2	(10)	(30)	–
Gas measurement differences		7	–	(4)	2	5	(25)
System operating costs – fuel		(3)	–	5	(6)	(4)	7
Monthly fixed customer charge estimate – revised methodology		–	–	–	–	–	7
Other margin[4]		(7)	(2)	(3)	6	(6)	13
Total gas distribution margin variance		**(11)**	**(3)**	**(7)**	**(12)**	**(33)**	(10)
Storage and transportation revenue		2	5	1	11	19	1
Other revenues		–	(2)	(1)	–	(3)	1
Expenses		(7)	(3)	–	(5)	(15)	(10)
Other income		–	–	–	1	1	(11)
Interest expense		3	–	1	(3)	1	8
Income taxes		5	2	6	–	13	(10)
Total variance to prior period		**(8)**	**(1)**	–	**(8)**	**(17)**	**(31)**
Net income (loss) for the period ended:	**2005**						**121**
	2006	**75**	**5**	**(10)**	**34**	**104**	

Three Months Ended March 31

Net income for the three months ended March 31, 2006 was $8 million lower as compared to the same period in 2005. This decrease was largely due to an unfavourable impact of warmer weather, higher operating expenses, which are the result of an increase in salary and wage costs and higher pension and post-retirement benefit costs, and an unfavourable impact due to lower usage. These were partially offset by the absence of a provision for earnings sharing in the first three months of 2006, a favourable variance due to gas measurement differences and customer growth.

Three Months Ended June 30

Net income for the three months ended June 30, 2006 decreased by $1 million as compared to the same period in 2005. The decrease in net income is mainly due to an unfavourable impact of warmer weather, higher operating expenses and other margin variances. Higher operating expenses are the result of increasing depreciation and property tax costs. These decreases were partially offset by a favourable variance due to increased storage revenue (the result of strong demand and favourable pricing due to warmer weather) and a favourable variance due to the impact of customer growth.

Three Months Ended September 30

Net loss for the three months ended September 30, 2006 and 2005 was $10 million. Although there was no difference in the net loss for the two periods, there were offsetting variances as noted in the table that

[4] Other margin variance is an accumulation of several individual less significant variances.

precedes this discussion. Most notably, compared to the same period in the prior year, the Company incurred a larger expense related to earnings sharing and a decline in customer usage. These two amounts were offset by a favourable income tax recovery caused by an increase in net loss before taxes, an increase in tax deductions, and a legislated elimination of the Federal Large Corporations Tax.

Three Months Ended December 31

Net income for the three months ended December 31, 2006 decreased by $8 million as compared to the same period in 2005. The decrease in net income is primarily due to an unfavourable impact of warmer weather and a larger charge to income related to earnings sharing. These decreases were partially offset by increased storage and transmission revenues.

RATE REGULATION

The Company is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act* (1998), which is part of a package of legislation known as *The Energy Competition Act* (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Distribution Rates

The OEB is mandated to approve rates that are just and reasonable. Utility earnings have historically been regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, unaccounted for gas volumes, inflation, the price of competing fuels, interest rates, general economic conditions and the Company's ability to achieve forecast revenues and manage costs.

Effective January 1, 2006, Union implemented new rates approved by the OEB in December 2005. Union's earnings for 2006 continued to be subject to the earnings sharing mechanism implemented by the OEB in 2005. Earnings in 2006 above an allowable rate of return on equity, normalized for weather, may be shared equally between ratepayers and the Company. Based on the actual year-end results and adjusted for the financial effects of warmer than normal weather, the Company has recognized $13 million as potentially payable to customers. The Company expects to apply to the OEB for the disposition of the earnings sharing amount, as well as other non-commodity deferral account balances, during the second quarter of 2007.

On August 25, 2006, the OEB issued a decision on certain common issues related to the Demand Side Management ("DSM") activities of the Company and Enbridge Gas Distribution. Most of the issues were the subject of a settlement agreement with intervenors. In that decision, the OEB accepted a formulaic approach to establishing annual DSM savings targets, budgets and utility incentives for a three-year plan term effective January 1, 2007. The result of this decision is an increase to the Company's DSM budget and an opportunity to earn in excess of $4 million annually if the DSM savings target is achieved or exceeded. The Company has subsequently applied to the OEB for approval of its 2007 DSM programs, which it received on January 26, 2007.

On November 7, 2006, Union received a decision from the OEB on the regulation of rates for gas storage services in Ontario. As a result of its finding that the market for storage services is competitive, the OEB will not regulate the rates for storage services to customers outside Union's franchise area or the rates for new storage services to customers within its franchise area. Existing storage services to customers within Union's franchise area will continue to be provided at regulated cost-based rates. The decision creates an unregulated storage operation within Union and provides the support required for new storage investment. Since the issuance of the decision, five parties who participated in the storage regulation proceeding have appealed various aspects of the decision to the OEB. The OEB heard submissions during a hearing held March 5 and March 6, 2007 regarding whether those parties have met the threshold for an appeal review. The OEB's decision is expected later this year.

In December 2006, the OEB issued a final rate order for new rates effective January 1, 2007, reflecting the outcomes from the Union's 2007 rate application, the DSM proceeding and the storage regulation decision. The average rate increase is approximately 3.1% and includes the impact of an increase in the common equity component of Union's capital structure from 35% to 36% and a decrease in the allowed return on equity from 9.63% to 8.54%.

Sale of Base Pressure Gas

On January 30, 2007, the OEB issued a second decision in connection with the Company's sale of base pressure gas in 2004 and its jurisdiction to apportion the gain on the sale (equal to $13 million) between the Company and ratepayers. Contrary to its initial decision, the OEB determined that it has the jurisdiction to apportion the gain on such asset sales between the Company and rate payers, but has not yet made a determination as to how or if that apportionment will be made. A hearing has been scheduled for May 2007. The Company has appealed the jurisdictional decision to the Divisional Court of Ontario pending the outcome of any exercise of the OEB's jurisdiction in this matter. The Company does not expect there to be a material impact on net earnings from this item.

Permit Fees

Effective January 1, 2007, the Government of Ontario has granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. Union is unable to determine with certainty the costs associated with such a change as it will be dependent on the number of municipalities that proceed to implement a permit fee and the amount of any such fee. As Union accesses its pipelines tens of thousands of times annually even a modest fee may have a significant impact. Union's approach in responding to this regulatory change is currently under consideration. One of the options available to Union is to make an application to the OEB to recover the estimated annual cost of these fees in rates.

Commodity Rates

The Company and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis ("Quarterly Rate Adjustment Mechanism"), to ensure that customers' rates reflect future expected prices to the extent reasonably possible. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These differences are included in quarterly gas commodity rates and recovered from or refunded to customers over the subsequent 12 months and are also subject to review and approval by the OEB on an annual basis. This allows the Company to adjust customer rates closer to the time of incurrence.

LIQUIDITY AND CAPITAL RESOURCES

The Company meets its short-term cash requirements through funds generated from operations, issuance of short-term debt and access to its lines of credit. Capital requirements are met through the issuance of long-term debt, preference shares, and common equity investment by the Company's parent.

Operating Activities

Typically, the primary factors impacting cash flow from operations are collections of accounts receivable balances, changes to inventory balances, payables for gas purchases and for amounts owing to suppliers and marketers. Fluctuations in weather, commodity rates, and gas prices, as well as the timing of recovery of certain costs, directly impact cash flows from operations.

The Company's heating season extends from approximately November through March. The Company begins the heating season with near capacity inventory levels which are drawn from throughout the heating season. As the majority of the first two quarters are part of the heating season, inventory levels decrease from December and thus contribute to a positive cash flow from operations. After the heating season ends, inventory is replenished for the next heating season. During the third quarter, gas inventory injections typically exceed withdrawals, negatively affecting cash flows. During the fourth quarter inventory decreases as withdrawals exceed injections.

Many of the Company's customers purchase gas directly from Marketers. Marketers typically deliver gas to the Company evenly throughout the year, whereas their customers use gas based on the heating season. As part of its normal billing process, the Company bills the Marketers' customers as gas is used and remits this cash to the Marketer when gas is delivered to Union. Therefore, during the first and second quarters of the year, customers have used more gas than has been delivered to the Company and Union has collected cash from the Marketers' customers creating a positive cash flow. During the third and fourth quarters, Marketers deliver more gas than their customers use, thus creating a significant cash outflow during the third and fourth quarters. These are normal seasonal trends.

Cash flow provided by operating activities was $451 million and $249 million for 2006 and 2005, respectively. These cash flows from operations are representative of the normal trends discussed above.

The $202 million increase in cash flow provided from operations in 2006 compared to 2005 is primarily due to a greater differential between the actual cost of gas and the cost of gas recovered through rates, during 2006. These amounts will be refunded to customers through the Quarterly Rate Adjustment Mechanism during 2007.

Cash flow provided by operating activities for the three months ended December 31, 2006 was $63 million in 2006 and used by operating activities in 2005 was $72 million. The increase in cash provided by operating activities is due primarily to a greater differential between the actual cost of gas and the cost of gas recovered through rates in 2006.

Investing Activities

Capital expenditures totalled $340 million in 2006 compared to $231 million in 2005. Of the total 2006 investment, 44% was spent primarily on transmission projects, 31% on distribution projects and 25% on general equipment. Approximately 62% was spent on maintenance projects and the remaining 38% was spent on expansion projects. These investments were necessary to meet the growth in customer demand for services and were funded through a combination of cash flow from operations and debt facilities. Actual capital expenditures in 2006 were less than expected due primarily to cancellation of the Thunder Bay Project (see Outlook discussion that follows).

Capital expenditures are expected to be approximately $332 million in 2007 with the allocation being approximately 44% on transmission and storage projects, 30% on distribution projects and 26% on general equipment. Approximately 56% of these expenditures are expected to be on maintenance projects and the remaining 44 % on expansion projects.

As outlined in the financing activities discussion that follows, the Company has sufficient financing available to meet its investing requirements. Management expects that financing of 2007 projects will be done through a combination of cash generated from operations, available debt facilities, issuance of additional debentures and from the issuance of additional equity.

Financing Activities

The Company has the following financing arrangements in place:

- A shelf prospectus filed in July 2006 permits the issuance of up to an aggregate of $600 million of medium-term notes ("MTN"). The shelf prospectus will expire in August 2008. As of December 31, 2006, $310 million was unused.
- A committed credit facility was renewed in June 2006 with the total availability being increased from $300 million to $400 million through June 2007. As of December 31, 2006, $400 million was unused.
- The Company has a $25 million operating facility available to help meet its short-term financing needs. As of December 31, 2006, $20 million was unused.

During the year the Company issued the following MTN debentures:

- $165 million at 5.46% per annum, issued on September 11, 2006, due September 11, 2036.
- $125 million at 4.85% per annum, issued on November 23, 2006, due April 25, 2022.

The proceeds from these issues were used to refinance maturities that occurred in late 2006, to finance capital expansion, and for general corporate purposes. The indentures and agreements relating to the Company's long-term debt obligations contain covenants limiting the payment of dividends. Certain debenture issues limit the payment of dividends such that dividends are not permitted, with certain exceptions, if immediately thereafter all indebtedness for money borrowed would exceed 75% of the total capitalization of the Company. The Company is in compliance with these provisions.

Long-term debt repayments in 2006 and 2005 totalled $83 million and $108 million, respectively, including repayments on sinking funds which totalled $8 million in each of 2006 and 2005.

The Company plans on issuing additional long-term debt in 2007 in order to replace a portion of the $200 million long-term debt which will be repaid in December 2007.

The $400 million committed credit facility enables the Company to borrow directly from banks, issue bankers' acceptances and support a commercial paper program. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime. During the term of the committed credit facility, the Company has the option to convert a portion of the drawings under the facility to loans not exceeding twelve months to maturity.

The short-term borrowing levels fluctuate significantly during the year due to the funding of construction activities, the timing of long-term debt issues, maturities and other financing activities, and the seasonality of the Company's business. The 2006 short-term borrowings peaked in January at approximately $96 million. Due to warmer than normal weather and the price of gas relative to the price of gas recovered from customers, it was not necessary to utilize the committed credit facility subsequent to January.

During 2006, the OEB approved an increase in the common equity component of the Company's capital structure from 35% to 36% effective January 1, 2007. In order to maintain the common equity component of the rate base at the level no greater than that approved by the OEB, the Company typically has paid a quarterly dividend of $16 million to its parent as well as an additional dividend as required. During 2006, the Company paid the usual quarterly common dividend for the first three quarters but suspended the fourth quarter dividend to allow the common equity component to increase to the allowed 36%. The Company expects payment of the quarterly common dividend to resume during the second half of 2007.

During 2005, the Company paid dividends of $16 million to its parent in each quarter as well as an additional $50 million dividend in March 2005 to maintain the 35% allowed common equity component.

FINANCIAL CONDITION

The Company's Dominion Bond Rating Service ("DBRS") credit ratings remain unchanged from the information filed in the Company's Annual Report for the fiscal year ended December 31, 2005. On April 24, 2006, DBRS affirmed the credit ratings along with their trend/outlook as stable for Union. DBRS again affirmed those ratings on February 20, 2007. In May 2006, Standard & Poor's ("S&P") changed the outlook of Union to positive following Duke Energy's announcement to sell Cinergy's commercial trading and marketing operations and in June 2006, S&P changed the outlook of Union to developing following Duke Energy's announcement to separate the electric and gas businesses. S&P noted the developing outlook reflects a measure of uncertainty as to how the new gas company will be capitalized and funded. In September 2006 S&P changed the outlook for Union back to Positive following the completion of their assessment of Duke Energy's announcement of the separation of the electric and gas businesses. On January 2, 2007, S&P changed the Company's credit ratings on debentures and preferred shares to BBB+ and P-2 (low) respectively. The overall outlook for Union was changed to Stable reflecting Union's strong business profile partially offset by volatility in natural gas prices affecting operating requirements.

	Standard & Poor's	**Dominion Bond Rating Service**
Commercial paper	A – 2	R – 1 (low)
Debentures	BBB+	A
Preferred shares	P – 2 (low)	Pfd – 2

CONTRACTUAL OBLIGATIONS

The table below is a summary of the Company's contractual payment obligations, due by period.

($millions)	Total	2007	2008-2009	2010-2011	Thereafter
Long-term debt	2,183	208	138	597	1,240
Capital lease obligations	4	1	3	–	–
Purchase obligations	1,136	597	233	106	200
Operating leases	21	5	8	7	1
Redeemable preferred shares	5	–	1	1	3
Total contractual obligations	3,349	811	383	711	1,444

Purchase obligations include distribution and storage and transportation contracts for periods through 2017, the cost of which are recognized as services are provided. Union has signed these contracts in the normal course of business.

For 2007, the Company anticipates its contribution for employee future benefits to be approximately $36 million.

RELATED PARTY TRANSACTIONS

The Company purchases gas and transportation services at prevailing market prices and under normal trade terms from commonly controlled companies. During the year ended December 31, 2006, these purchases totalled $10 million (2005 - $44 million). The Company also provides storage and transportation services to commonly controlled companies under normal trade terms. During the year, this revenue totalled less than $1 million (2005 - $5 million).

The Company provided administrative, management and other services to commonly controlled companies totalling $6 million (2005 - $6 million), which were recovered at cost. Charges from related parties for administrative and other goods and services were $12 million (2005 - $12 million), which were billed to the Company at the service provider's cost.

At December 31, 2006 the Company has intercompany receivable balances of $1 million (2005 - $2 million) and intercompany payable balances of $1 million (2005 - $17 million), which are recorded in accounts receivable and accounts payable, respectively.

During the year, the Company obtained from and provided short-term unsecured loans to its parent company, Westcoast Energy Inc. There was no balance on these loans outstanding at December 31, 2006 (2005 - $56 million payable). When these loans have a payable balance, they are classified as short-term borrowings, and when these loans have a receivable balance, they are classified as cash and cash equivalents. Interest received on these loans was less than $1 million (2005 - $1 million) and the interest paid on these loans totalled less than $1 million in 2006 and 2005. Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

FINANCIAL INSTRUMENTS

The fair market values of accounts receivable and current liabilities approximate carrying values. Judgement is required in interpreting market data to develop the estimates of fair value of financial instruments. Accordingly, the estimates determined as of December 2006 and 2005, are not necessarily indicative of the amounts that the Company could have realized in the markets. Fair market values have been estimated by reference to quoted market prices for the actual or similar instruments where available.

GAS SUPPLY

The gas supply portfolio of the Company includes both fixed price contracts and contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. These contracts are primarily indexed to either the New York Mercantile Exchange natural gas futures contracts or the Canadian Gas Price Reporter that publishes Alberta index prices.

The Company has a risk management policy that is designed to reduce the price volatility of its gas supply. Both financial and physical hedges are used to reduce pricing volatility of the underlying physical gas supply contracts. The risk management policy has been reviewed and approved by the OEB in prior rate proceedings.

During the year ended December 31, 2006, the Company hedged the purchase price of 40 Petajoules[5] ("PJ") or 38% of the total gas supply portfolio of 106 PJs using a variety of risk management tools.

Consistent with past practices, as of December 31, 2006, approximately 79% of the Company's forecast gas supply of 114 PJs for the period January 1, 2007 to December 31, 2007 was not hedged. The balance of the portfolio consists of fixed price contracts or has been effectively hedged through the use of financial options and swaps that mature prior to December 2007. The Company has paid $11 million in option fees for these hedge agreements which at December 31, 2006 had an unrealized loss of $8 million. The option fees are recorded as a deferred charge receivable and will be expensed in the same period as the gain or loss on the related hedge is recognized as gas costs.

Gas costs are included in customer rates based on forecasted gas supply approved by the OEB. Differences between the OEB approved reference prices and the actual cost of gas purchased, including the impact of both the indexed purchase prices and any hedging activities, are recovered from or refunded to customers through the quarterly rate mechanism and subsequently reviewed and approved by the OEB on an annual basis.

OUTLOOK

Gas Sales and Distribution

The Company's outlook for 2007 and 2008 is for an overall decline in total gas consumption. Moderate volumetric growth in new customers is expected to be offset by permanent demand reductions from existing customers due to the impact of customers' increasing focus on conservation and efficiency, a warming trend that is not fully reflected in rates and increasing business closures. However, the Company expects growth in peak day demands.

New customer growth has been strong over the last few years; however current levels of new construction may not be sustained in 2007 and 2008 which could lead to a slowdown in the number of new customers

[5] A joule is the international unit for measuring energy. A Petajoule ("PJ") = 1 x 1015 joules.

added in the residential market. Union is experiencing a reduction in distribution throughput as a result of energy conservation including its DSM initiatives and a general trend towards warmer weather and expects this trend to continue going forward. In addition, the Ontario Ministry of Energy has committed to aggressively promoting a conservation culture across the province that is expected to further reduce energy consumption, with corresponding impacts on the Company's volume-based revenue.

The Company continues to support focused efforts to promote conservation and energy efficiency through its DSM programs. In 2006, the Company spent $13 million promoting these programs. Further, in response to the volatility of natural gas commodity prices the Company expects customers to focus on reducing gas consumption by increasing investments in energy efficiency and conservation.

Consumer spending and concern over the reliability of electricity supply may create an opportunity to increase the penetration of natural gas appliances such as fireplaces, clothes dryers, ranges and grills in the residential market. Further, changes in the electricity market may also create a renewed interest in natural gas fired "stand by" generation.

High natural gas prices and the higher Canadian dollar are also putting pressure on Canadian manufacturing companies. The Company expects a reduction in industrial demand for gas as a result of production slow downs and a continued increase in industrial plant closures in Ontario.

Storage and Transportation

Management expects overall demand for natural gas in North America to grow at a rate of two percent per year along with continued growth in peak day demands. Additional storage and transmission infrastructure will be required to bring new sources of gas supply to market. The location of Union's storage and transmission facilities, with interconnections between major U.S. markets in the Great Lakes region and the Northeast supports growth opportunities for Union.

Since late 2004 the Company has conducted a number of open seasons to determine market need for new transportation and storage capacity. Union completed and put into service in late 2006 two new sections of 48" pipeline on the Dawn-Trafalgar system and new compression facilities at the Dawn Hub at a total cost of approximately $156 million. This expansion increased the capacity on the Dawn-Trafalgar transmission system by approximately 360 mmcfd.[6]

During 2006, Union received approval from the OEB to construct a new section of pipeline on the Dawn-Trafalgar system. This 48" pipeline expansion, along with the planned expansion of compression capacity at the Company's Parkway compressor station will further increase the capacity of the Dawn-Trafalgar transmission system by approximately 480 mmcfd at a cost of approximately $125 million. Construction is planned to start in early 2007 with service to begin November 1, 2007.

During 2006, Union conducted further open seasons for transportation and storage services to meet customer demand requirements for 2008. Union is currently in the process of executing contracts with customers to fully support the 2008 expansion of compression facilities on the Dawn Trafalgar transmission system. This expansion will increase capacity by approximately 350 mmcfd at a cost of approximately $60 million. Union has recently executed contracts with customers to support a 2008 expansion of its storage capability at the Dawn Hub. This expansion will increase storage deliverability by approximately 500 mmcfd at a cost of approximately $100 million. Proceeding with the Dawn Hub storage expansion was contingent on OEB endorsement of market pricing for the services provided by the expansion as well as agreeing to forbear from regulating new storage services. These conditions were ultimately supported by the OEB's November 7, 2006 decision, which is currently under consideration for

[6] Mmcfd equals millions of cubic feet per day

review by the OEB. The storage deliverability expansion will support the need for new storage services and capacity as negotiated with customers and approved by the OEB as part of the Natural Gas Electricity Interface Review ("NGEIR") proceeding. This expansion is critical to meet the requirement for additional capacity to serve new gas fired electricity generation in Ontario.

The Ontario government's plan to meet Ontario's increasing electricity demand and deal with existing power generation requirements includes building new gas fired and renewable generation capacity, retiring coal-fired generation, and encouraging conservation to reduce demand. These plans may continue to create additional opportunities for new gas fired power plants in both Union's service territory and the surrounding markets in Ontario. It may also provide opportunities for increased penetration of natural gas appliances in response to electricity conservation through fuel switching.

Three new large gas fired power plants have been announced in Union's service territory: St. Clair Energy Centre ("SEC") and the Greenfield Energy Centre ("GEC") in the Sarnia area are planned to be on line in 2007. Union has executed contracts to provide service to SEC starting in late 2007. This will involve the construction of new pipeline and related facilities at a total cost of approximately $13.5 million. The Greenfield Energy Centre Limited Partnership received approval from the OEB to construct a natural gas pipeline to serve the planned GEC power plant. GEC is proceeding to construct this line which will represent a by-pass of Union's distribution facilities. However, Union has entered into service contracts with GEC to provide ex-franchise storage and related services from the Dawn Hub. A new Halton Hills plant was recently announced as part of the government's power request for proposal process and is projected to be in service during 2009.

The government of Ontario had announced plans in August 2005 to convert the Ontario Power Generation ("OPG") coal-fired generating station, in Thunder Bay, to natural gas by 2007. Union began work on the pipeline and related facilities for OPG in early 2006. In June 2006, the Government of Ontario announced that it was no longer supportive of the Thunder Bay conversion to natural gas. As such, Union shut down the project and was reimbursed by the OPG for all related costs incurred by the Company.

The Company's rates effective January 1, 2008 and for a three to five year period thereafter, are expected to be set through the use of an incentive regulation framework. An incentive regulation pricing framework establishes new prices at the beginning of each year through the application of a pricing formula rather than through an examination of revenue and cost forecasts. Typically, the pricing formula under incentive regulation includes an allowance for inflationary cost increases, an adjustment for declines in natural gas use by customers, and a reduction for expected productivity gains. There is usually little change in the use of deferral accounts, such as those employed by the Company for gas cost variances. The OEB intends to conduct a proceeding during 2007 that will establish the incentive regulation framework, including the pricing formula and other parameters, for the Ontario natural gas utilities. The Company will participate in the OEB proceeding.

Effective January 1, 2007, the Government of Ontario has granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. Union is unable to determine with certainty the costs associated with such a change as it will be dependent on the number of municipalities that proceed to implement a permit fee and the amount of any such fee. As Union accesses its pipelines tens of thousands of time annually even a modest fee may have a significant impact. Union's approach in responding to this regulatory change is currently under consideration. One of the options available to Union is to make an application to the OEB to recover the estimated annual cost of these fees in rates.

RISK FACTORS

The Company's earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, the earnings level may be adversely affected by a number of risks as described below:

Market Risk

Sales to industrial customers are affected by general economic conditions and the absolute and relative price of alternative energy sources. In 2007, the Company expects that the sustained higher gas price environment and price volatility, the strength of the Canadian dollar and the competitive position of oil relative to natural gas are significant risks that the Company will seek to manage.

Union's industrial markets have been experiencing a significant amount of demand reduction related to plant closures and energy efficiencies resulting in permanent demand losses.

Sales to Union's residential, small commercial and small industrial customers are affected by the number of new customer additions to the system, the price of natural gas, the warming trend in weather that is not fully reflected in rates, the preference for natural gas products and services, and the continued shift to higher efficiency products. New customer additions are expected to soften in 2007 from 2006 levels. In 2007, the ongoing trend towards energy efficient products will continue to put pressure on Union's normalized average usage. Further, the current trend toward owning a water heater versus rental options exerts pressure on Union's market share, as the initial cost to purchase an electric water heater is less than the cost of a gas water heater.

Sales to ex-franchise storage and transportation customers can be affected by the expiry of existing long term contracts. A significant quantity of transportation capacity is now subject to renewal on an annual basis. Specifically, customers with capacity expiring in 2009 are required to provide notice of their intent to re-contract for the expiring capacity in 2007. Union's standard contract terms and conditions result in customer contracts automatically renewing at the initial term on an annual basis subject to the customer providing two years prior notice of termination. Although it is possible some capacity may be terminated, Union will monitor this and endeavour to ensure that the capacity remains fully optimized.

Commodity Price Risk

Fluctuations in natural gas prices affect the Company's gas purchase costs for its own operating requirements as well as the gas supply costs it incurs for, and collects from, its system customers. The Company manages gas procurement through a risk management committee and purchasing policies, and employs both fixed and variable price contracts. Gas purchase options are used to manage price volatility with respect to underlying indexed gas supply contracts and include the use of natural gas swaps, price caps and collars. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers.

Credit Risk

Credit risk represents the loss that the Company would incur if a customer fails to perform under its contractual obligations. Where exposed to credit risk, the Company analyzes the customer's financial condition prior to entering into an agreement, obtains collateral when appropriate, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis. The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2006 was $79 million (2005 - $58 million). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers.

Weather Risk

The rates approved by the OEB are impacted by weather, as a primary component of the Company's rates are volume based. The volume forecasts used to determine the rates approved by the OEB assume normal weather conditions. Normal weather, as mandated by the OEB, is based on a 55:45 weighting of the 30-year average forecast and 20-year trend forecast, respectively, for 2007 and beyond. Since a large portion of the gas distributed to the residential and commercial market is used for space heating and is charged using volume-based rates, differences from normal weather have a significant effect on the consumption of gas and the Company's financial results.

Regulatory Risk

The Company's rates effective January 1, 2007 have been finalized by the OEB. These rates will also form the base for an incentive regulation pricing framework to be effective January 1, 2008 and for a three to five year term thereafter. The incentive regulation pricing framework establishes new prices at the beginning of each year through the application of a pricing formula rather than through an examination of revenue and cost forecasts as part of an annual cost of service hearing. Typically, the pricing formula includes an allowance for inflationary cost increases, an adjustment for declines in natural gas use by customers, and a reduction for expected productivity gains. There is usually little change in the use of deferral accounts, such as those employed by the Company for gas cost variances. The OEB intends to conduct a proceeding during 2007 that will establish the incentive regulation framework, including the pricing formula and other parameters, for the Ontario natural gas utilities. This framework could have a material impact on the future rates, new capital investments and earnings of the Company.

On January 6, 2006 the Ontario Energy Board issued a decision approving an application made by Greenfield Energy Centre Limited Partnership to construct a natural gas pipeline to serve the planned 1005 Megawatts ("MW") gas-fired generating station being built near Sarnia, Ontario bypassing the Company's distribution facilities. The Board's decision to approve a physical by-pass of the distribution company is unprecedented, signifies a shift in the policy and regulatory treatment of natural gas service in Ontario and creates significant regulatory uncertainty. The decision increases the risk profile faced by natural gas distribution companies in Ontario and may have a material impact on the Company's short term earnings and in the long term could have an impact on the level and structure of future rates charged to customers

Sale of Base Pressure Gas

On January 30, 2007, the OEB issued a second decision in connection with the Company's sale of base pressure gas in 2004 and its jurisdiction to apportion the gain on the sale (equal to $13 million) between the Company and ratepayers. Contrary to its initial decision, the OEB determined that it has the jurisdiction to apportion the gain on such asset sales between the Company and rate payers, but has not yet made a determination as to how or if that apportionment will be made. A hearing has been scheduled for May 2007. The Company has appealed the jurisdictional decision to the Divisional Court of Ontario pending the outcome of any exercise of the OEB's jurisdiction in this matter.

Permit Fees

Effective January 1, 2007, the Government of Ontario has granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. Union is unable to determine with certainty the costs associated with such a change as it will be dependent on the number of municipalities that proceed to implement a permit fee and the amount of any such fee. As Union accesses its pipelines tens of thousands of times annually even a modest fee may have a significant impact. Union's approach in responding to this regulatory change is currently under consideration. One of the options available to Union is to make an application to the OEB to recover the estimated annual cost of these fees in rates.

Financing Risk

The Company is subject to long-term debt covenants that include requirements for specific interest coverage ratios prior to issuance of additional long-term debt. Although the company does not anticipate any impact to its current financing plans, reduced earnings, including a continued decline in ROE, may limit the level of new long-term debt available to the company.

Human Resources Risk

The Company's workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect the Company's ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent an emerging issue that must be addressed by the Company. The Company must maintain its ability to attract, train, and retain employees with the requisite skills and capabilities to operate in the complex and competitive energy industry.

Performance Risk

The Company has extensive contractual relationships with natural gas producers, customers, marketers, commercial enterprises, industrial companies, and others. The risk of non-performance by a contracting party may be analyzed and reduced but it cannot be entirely eliminated. Ongoing consolidation of customers, financial institutions and partners may increase the severity of a default.

Insurance Risk

While the Company maintains insurance against exposures to losses normally associated with transportation, distribution and storage of natural gas, including but not limited to coverage for explosions and fires, the occurrence of a significant event against which the Company may not be fully insured could have an adverse effect on its business.

Interest Rate Risk

The Company's business is capital intensive and often requires substantial financing. Significant movements in interest rates may expose the Company to higher borrowing costs. Interest rates are also a key factor in the pension cost assumptions. Significant movements in interest rates will impact earnings.

Litigation Risk

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, the Company has no reason to believe that the ultimate outcome of such matters currently known to the Company would have a material effect on its financial position.

Facility Risk

The Company carries on business through a large and complex array of natural gas transmission, storage and distribution assets. These facilities, like any other industrial operations, are subject to outages from time to time. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Political Risk

The Ontario Power Authority ("OPA") is the organization responsible for the long-term planning for Ontario's electricity system. The OPA has determined that demand for electricity is expected to grow over the next 20 years. Over that same period, most of the nuclear plants will reach the end of their useful lives, where those nuclear plants currently produce approximately 50% of Ontario's electricity. Also, the Ontario government has committed to close all of the coal-fired generating plants in the province in order to reduce air emissions and their attendant health impacts, where those plants currently produce approximately 20% of Ontario's electricity. These circumstances combine to create a forecast shortfall in electricity supply of approximately 24,000 MW of Ontario's current capacity. These circumstances also create greater likelihood for government intervention in the provincial energy sector, some of which may affect the Company.

Environmental, Health and Safety Risk

The Company highly values the health and safety of its employees, customers and communities. Protecting and responsibly managing natural resources are critical to the quality of life in the areas that the Company serves, the environment and the Company's long-term business success. The Company has continued its implementation of an environment, health and safety management system to ensure continued compliance with applicable regulations and to provide a consistent approach to policies, programs and procedures.

The production, transmission, delivery and consumption of energy all have potential for associated environment, health and safety ("EHS") impacts. As a result, these activities are subject to a comprehensive framework of federal, provincial and local laws, regulations and guidelines. The Company actively engages with government and other stakeholders to affect the development of this regulatory framework. At this time, the existing EHS requirements are not expected to materially adversely affect the Company's competitive position, capital expenditure program or level of earnings.

The United Nations-sponsored Kyoto Protocol, which prescribes specific greenhouse gas emission reduction targets for developed countries, came into force on February 16, 2005. Under the Protocol, Canada has an obligation to reduce average greenhouse gas emissions to 6% below the 1990 level over the period 2008 to 2012. In October 2006 the proposed Clean Air Act ("CAA") was introduced by the current federal Conservative government as an alternative to the previous Liberal government's plan to support the Kyoto Protocol. Under the proposed CAA, the government plans to establish new emission reduction targets for both greenhouse gases and air pollutants (i.e. nitrogen oxides, sulphur dioxide, particulate matter, volatile organic compounds and mercury). These targets are expected to come into effect starting in the 2010-2015 time period and will extend out to 2050, becoming more stringent over time. If the CAA is ultimately implemented, the Company will likely be subject to emission reduction targets beginning in 2010-2015. Compliance options are expected to be part of the regulatory framework, including a technology investment fund to support development of technologies such as CO_2 sequestration. The CAA is currently under review by a parliamentary committee.

The Company cannot estimate with certainty the potential effect of the Canadian greenhouse gas reduction policy currently under development on future consolidated results of operations, cash flows or financial position due to the uncertainty of the Canadian policy. The Company will continue to assess and respond to the potential implications of greenhouse gas policies.

Franchise Rights

The Company has approximately 305 franchise agreements with 230 municipalities in Ontario. These agreements set out the terms and conditions under which the Company conducts its business on municipal roadways.

Currently the Company is negotiating with various municipalities to renew agreements expiring within the next year. The Company expects that the OEB will renew its franchise rights in these areas in accordance with the 2000 Model Franchise Agreement.

CONTINGENCY

In 2004, the Company was served with two class action claims, seeking relief similar to a case filed against Enbridge Gas Distribution ("Enbridge"). In 1994, Enbridge, a gas distribution company located in Toronto, Ontario was served with a class action claim seeking, among other things, a declaration that the OEB-approved 5% late payment fee paid by Enbridge's customers since 1981 is interest that exceeds the amount permitted by the Criminal Code of Canada, and that by collecting the late payment fee, Enbridge had been unjustly enriched and those who paid the fee should be entitled to restitution. In December 2006 the court approved settlement of the claim commenced against Enbridge for $22 million, including $11 million in legal fees and expenses, $2 million to be paid to the Class Proceedings Fund (operated by the Law Foundation of Ontario) and a $9 million donation to the Winter Warmth Fund. The Company will participate in any proceedings before the OEB initiated by Enbridge to seek recovery of the settlement as it will establish an important precedent for the Company's ability to recover any settlement or liability with respect to Union's late payment class action.

By the date that the Company was served with the two class action claims, the structure of the OEB-approved late payment fees charged by the Company had changed from the 5% structure which was the subject of the two Supreme Court of Canada decisions. The Company has calculated the total amount of 5% late payment fees collected since 1994 to be up to $77 million. If the claimants were permitted to recover any portion of the amount claimed and the Company was required to refund the amount of such recovery, the Company would apply to the OEB to recover any amounts payable from ratepayers. Management is currently assessing the claims and anticipates that there will be no material financial impact on the Company from the ultimate resolution of those claims. However, if the claimants prevail, the cash outflows could occur in a different period than the requested recovery from ratepayers. As such, there could be a significant impact to the Company's cash flow from operating activities.

OUTSTANDING SHARES

	2006	2005
Redeemable Preferred Shares		
Class A, Series A, 5.5%	47,672	49,772
Class A, Series C, 5.0%	49,500	49,500
Preferred Shares		
Class A, Series B, 6.0%	90,000	90,000
Class B, Series 11, 4.79%	4,000,000	4,000,000
Common Shares	57,822,650	57,822,650

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the President, acting as the Chief Executive Officer, and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by the annual filings and has concluded that the disclosure controls are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely fashion. The required information was effectively recorded, processed, summarized and reported within the time period necessary to prepare the annual filings. The disclosure controls and procedures are effective in ensuring that information required to be disclosed pursuant to applicable security laws are accumulated and communicated to management, including the President, acting as the Chief Executive Officer, and the Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Management has also designed internal controls over financial reporting for the Company to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles. Management has determined that there has been no change in internal control over financial reporting for the Company that occurred during the reporting period that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

The financial statements and all information in this report have been prepared by and are the responsibility of management. The financial statements have been prepared in conformity with Canadian generally accepted accounting principles and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised entirely of directors who are not employees of the Company.

The Audit Committee meets regularly with management, the internal auditors and the shareholders' auditors to review the financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Audit Committee, as does the Director of Internal Audit Services. The Audit Committee reports its findings to the Board of Directors.

Deloitte & Touche LLP performed an independent audit of the 2006 and 2005 financial statements in this report. Their independent professional opinion on the fairness of these financial statements is included in the Auditors' Report.

March 23, 2007

JULIE DILL	**GREGORY L. EBEL**
President	Chief Financial Officer

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AUDITORS' REPORT

To the Shareholders of Union Gas Limited

We have audited the balance sheets of Union Gas Limited as at December 31, 2006 and 2005 and the statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
March 23, 2007

UNION GAS LIMITED
Statements of Income

For the Years Ended December 31 ($millions)	**2006**	2005
Gas sales and distribution revenue	**1,855**	1,876
Cost of gas (note 20)	**1,249**	1,237
Gas distribution margin	**606**	639
Storage and transportation revenue (note 20)	**191**	172
Other revenue	**33**	36
	830	847
Expenses		
Operating and maintenance (note 20)	**310**	303
Depreciation and amortization (note 7)	**163**	156
Property and capital taxes	**63**	62
	536	521
Income before other items	**294**	326
Other income	**2**	1
Earnings before interest and income taxes	**296**	327
Interest expense (notes 9, 11 and 20)	**155**	156
Income before income taxes	**141**	171
Income taxes (note 19)	**37**	50
Net income	**104**	121
Preference share dividends	**5**	5
Earnings applicable to common shares	**99**	116

(See accompanying notes)

UNION GAS LIMITED
Statements of Retained Earnings

For the Years Ended December 31 ($millions)	**2006**	2005
Retained earnings, beginning of year	**472**	471
Net income	**104**	121
Dividends		
Preference shares	**(5)**	(5)
Common shares	**(49)**	(115)
Retained earnings, end of year	**522**	472

(See accompanying notes)

UNION GAS LIMITED
Balance Sheets

As at December 31 ($millions)	**2006**	2005
Assets		
Current assets		
Cash and cash equivalents (note 3)	**109**	–
Accounts receivable (notes 4, 5 and 20)	**429**	463
Inventories (note 6)	**340**	307
Deferred income taxes (note 19)	**71**	–
Total current assets	**949**	770
Property, plant and equipment, net (note 7)	**3,376**	3,133
Investments and other assets (note 8 and 18)	**235**	223
Total Assets	**4,560**	4,126
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term borrowings (notes 3, 9 and 20)	–	154
Accounts payable and accrued charges (notes 5, 10 and 20)	**676**	502
Income taxes payable (note 19)	**105**	2
Deferred income taxes (note 19)	–	10
Long-term debt and obligation under capital lease due within one year (note 11)	**209**	84
Total current liabilities	**990**	752
Long-term liabilities		
Long-term debt and obligation under capital lease (notes 11 and 17)	**1,978**	1,897
Mandatorily redeemable preference shares (notes 12 and 17)	**5**	5
Deferred income taxes (note 19)	**223**	233
Asset retirement obligations (note 14)	**67**	1
Deferred credits (note 18)	**41**	33
Other long-term liabilities	**1**	–
Total long-term liabilities	**2,315**	2,169
Total Liabilities	**3,305**	2,921
Shareholders' equity		
Share capital (note 13)	**732**	732
Contributed surplus (note 15)	**1**	1
Retained earnings	**522**	472
Total Shareholders' Equity	**1,255**	1,205
Total Liabilities and Shareholders' Equity	**4,560**	4,126

Contingencies (notes 16 and 21) *(See accompanying notes)*

Approved by the Board

Director

Director

UNION GAS LIMITED
Statements of Cash Flows

For the Years Ended December 31 ($millions)	**2006**	2005
Operating Activities		
Net income	**104**	121
Items not affecting cash		
Depreciation and amortization	**165**	158
Gain on foreign exchange	–	(1)
Deferred income taxes	**(91)**	20
Non-cash changes in working capital		
Accounts receivable	**55**	(46)
Inventories	**(33)**	(12)
Account payables, accrued charges and other	**251**	9
	451	249
Investing Activities		
Additions to property, plant and equipment	**(340)**	(231)
	(340)	(231)
Financing Activities		
(Decrease) increase in short-term borrowings	**(154)**	6
Increase in obligation under capital lease	–	3
Long-term debt issued	**290**	200
Long-term debt retired	**(83)**	(108)
Other long-term liabilities	**(1)**	1
Dividends paid	**(54)**	(120)
	(2)	(18)
Change in cash and cash equivalents, during the year	**109**	–
Cash and cash equivalents, beginning of year	–	–
Cash and cash equivalents, end of year (note 3)	**109**	–

(See accompanying notes)

UNION GAS LIMITED
Notes to Financial Statements
December 31, 2006 and 2005

Union Gas Limited (the "Company") owns and operates natural gas transmission, distribution and storage facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy participants in Ontario, Quebec and the United States. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the transportation, storage and distribution of natural gas. In total, the Company has over 4,000 kilometres of high-pressure transmission pipeline and approximately 35,000 kilometres of distribution pipeline. The Company's underground natural gas storage facilities have a working capacity of approximately 150 Bcf and are the largest in Canada.

1. Significant Accounting Policies

Accounting Principles

The financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates. Management's significant estimates include unbilled revenue, a provision for doubtful accounts, income tax expense, employee future benefit expense and asset retirement obligations.

Accounting Estimates

Effective January 1, 2005, the Company changed its method of recognizing the amount by which actual gas measurement differences vary from estimated levels. The previous method was to defer the differences and amortize the deferral over three years. The Company will no longer defer such amounts to future periods and will recognize all gas measurement differences in the year of occurrence. The effect of this change was a decrease in pre-tax earnings of $10 million for the year ended December 31, 2005.

Effective January 1, 2005, the Company changed its method of interim period recognition of gas measurement differences. The revised methodology recognizes gas measurement differences in interim periods using a seasonal trend pattern compared to the straight-line method of recognition used in prior years. This change had no impact for the year ended December 31, 2005.

Effective January 1, 2005, the Company re-evaluated its methodology for calculating the estimate of the unbilled fixed monthly charge. The revised methodology is recognized as a change in estimate. This change increased pre-tax earnings by $7 million for the year ended December 31, 2005.

Regulation

The Company is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act* (1998), which is part of a package of legislation known as *The Energy Competition Act* (1998). This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and the Company's ability to achieve forecast revenues and manage costs.

2004 rates were established under traditional cost of service regulation. 2005 and 2006 rates were approved by the OEB on the basis of previously approved items.

In accordance with an OEB-imposed earnings sharing mechanism, actual earnings in 2006 above an allowable return on equity, normalized for weather may be shared equally between ratepayers and the Company. A provision of $13 million was recognized as a reduction of gas sales and distribution revenue and as an obligation in accounts payable and accrued charges for 2006.

The Company follows Canadian GAAP, which may differ for regulated operations from those otherwise expected in non-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in current period earnings.

On November 7, 2006, the Company received a decision from the OEB on the regulation of rates for gas storage services in Ontario. The OEB found the storage market is competitive. As a result the OEB will not regulate the prices of storage services to customers outside of Union's franchise area or the prices of new storage services to customers within its franchise area. Existing storage services to customers within the Company's franchise area will continue to be provided at cost-based rates. All other services continue to be regulated by the OEB.

Deferred Charges

Certain costs have been deferred for future recovery from customers based on approved OEB rate orders and mechanisms.

Costs related to long-term debt are deferred and amortized on a straight-line basis over the term of the respective debt issues.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using prices approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in either accounts receivable (note 4) or accounts payable and accrued charges (note 10) for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology recognized by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Natural Gas Risk Management Contracts

The Company's gas supply portfolio includes both fixed-price and variable-priced contracts. In order to manage the impacts of price volatility from variable-priced contracts, the Company enters into natural gas hedge contracts. The hedges are recorded at fair market value within accounts receivable (note 4). Since the Company is a regulated utility, any gain or loss is deferred for future disposition subject to approval by the OEB. The Company negotiates natural gas hedge contracts only with those institutions that have a credit rating of A- or higher with Standard and Poors, Moody's or Dominion Bond Rating Service.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short term investments with an original maturity of three months or less. See note 20 for discussion of related party transactions.

Income Taxes

Regulated operations

The Company records income tax expense for its regulated operations using the flow through tax accounting methodology as approved by the OEB (see note 19). Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Generally, rates and revenues for regulated utility operations include the recovery of only such income taxes that are currently payable. Accordingly, with the exceptions that follow, the Company does not provide for deferred income taxes. The flow through tax accounting methodology is followed for accounting purposes as there is reasonable expectation that all such taxes will be recovered when they become payable.

Certain exceptions to the flow through tax accounting methodology for regulated operations have been approved by the OEB. The Company calculates deferred income taxes on temporary differences between the approved cost and the actual cost of gas and on temporary differences arising on certain employee future benefits deferred in accounts.

Prior to 1997, the Company utilized the tax allocation method to account for income taxes. Under this method, provision was made for income taxes deferred principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the accounts. As approved by the OEB, this balance is reduced as the timing differences that gave rise to these deferred income taxes reverse, resulting in an additional exception to the flow through tax accounting methodology. The timing differences are expected to fully reverse by 2018.

Deregulated operations

On November 7, 2006 the OEB rendered its decision that it will no longer regulate the rates charged by Union for storage services to its customers outside of Union's franchise area or the rates charged to customers by Union for new storage services within its franchise area. The OEB decision outlined a four year transition period over which the financial impacts of this decision would be implemented. The result of this decision is that a portion of Union's storage business is no longer subject to regulation and as such the Company can no longer apply the flow-through methodology to that portion of the storage business. The Company is required to utilize the tax allocation method to account for accumulated timing differences related to assets used in those operations. The accumulated timing differences arise as a result of claiming capital cost allowance for income tax purposes in excess of or less than depreciation provided in the accounts. A long-term deferred income tax liability of $10 million has been recognized with respect to the accumulated timing differences on storage assets at December 31, 2006 (note 19).

Inventories

Gas in storage for resale to customers is carried at prices approved by the OEB in the determination of customer sales rates. The difference between the approved price and the actual cost of the gas purchased is deferred in either accounts receivable (note 4) or accounts payable and accrued charges (note 10) for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost, replacement cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment are carried at cost which includes all direct costs, overhead attributable to construction and interest capitalized during construction. The cost of property, plant and equipment is reduced by contributions and grants in aid of construction received from customers and governmental bodies in support of specific transmission and distribution facilities.

The original cost of depreciable units retired, together with the net cost of removal less salvage, is charged to accumulated depreciation. Under this method, no income or loss is recognized on ordinary retirements of depreciable property.

Depreciation is provided on the straight-line method at various rates based on the average service life of each class of property, ranging from 4 to 60 years. Depreciation rates are determined by periodic review and approved by the OEB.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation ("ARO"), where a legal obligation exists, as a liability in the period in which it is incurred provided a reasonable estimate of fair value can be determined. The associated asset retirement cost is added to the carrying amount of the related asset. The liability is accreted over the estimated life of the related asset.

Goodwill

Goodwill is included in investments and other assets (note 8) and represents the excess of the acquisition cost over the fair value of the identifiable net assets acquired. Goodwill is tested annually for impairment or more frequently if events or changes in circumstances indicate a potential impairment, by comparing the fair value of the goodwill with its carrying amount.

Stock-Based Compensation

The Company has one stock-based compensation plan, which is described in note 15. The Company accounts for stock-based payments to non-employees and direct awards to employees and non-employees by using a fair value-based method of accounting. Share appreciation rights ("SARs") and similar awards to be settled in cash or equity are accounted for by measuring the amount by which the quoted market price exceeds the option price at the balance sheet date. The Company uses the fair value-based method to account for all other stock-based transactions with employees.

The Company accounts for stock options by measuring the fair value of the stock options using the Black Scholes option pricing model. Compensation cost is then recognized over the vesting period. The Company accounts for phantom stock and performance shares by measuring the fair value of the instrument at the grant date and recognizing the cost over the vesting period. All expense amounts are recorded as a charge to operating and maintenance expense.

Employee Benefit Plans

The Company uses the projected benefit method prorated on services to account for defined benefit pension and post-retirement benefits other than pensions earned by employees.

The Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value. The calculation of the expected return on assets is based on the market-related value of assets.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The amount by which the net unamortized cumulative actuarial gain or loss exceeds ten percent of the greater of the accrued benefit obligation or the market-related value of plan assets at the beginning of the year is amortized over the average remaining service period of the active employees.

The average remaining service period of active employees covered by the pension plans and the post-retirement benefits other than pension plans is 11 and 18 years, respectively.

For defined contribution plans maintained by the Company, contributions payable by the Company are expensed as pension costs.

Financial Instruments

In April 2005, the Canadian Institute of Chartered Accounts ("CICA") released new standards related to financial instruments. These standards must be implemented no later than fiscal years beginning on or after October 1, 2006. Earlier adoption is permitted. The new standards comprehensively address when an entity should recognize a financial instrument on its balance sheet and how it should measure the instrument once recognized. The Company has completed the review of the requirements and adopted the provisions as of January 1, 2007. The Company rarely enters into contracts or other arrangements that fall within the scope of the new standards, and we have determined that the new guidance will not have a material effect on the Company's future results, position or cash flows.

Comparative Figures

Certain comparative figures have been reclassified to conform to the financial statement presentation adopted in 2006.

2. Financial Statement Effects of Rate Regulation

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. For certain of these regulatory items, the expected recovery/settlement period, or likelihood of recovery/settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. In the absence of rate regulation, balance sheet items presented below would be higher/(lower) by:

($millions)	**Financial Statement Location**	**Recovery/ Settlement Period**	**2006**	2005
Regulatory assets				
Gas cost deferrals	a	A	–	(31)
Other deferrals	a	A	**(25)**	(9)
Deferred mark-to-market losses	a	A	**(18)**	–
Gas in storage inventory	b	A	**(77)**	73
Deferred income taxes (current)	e	A	**2**	–
Asset removal costs	c	C	**367**	388
Total regulatory assets			**249**	421
Regulatory liabilities				
Gas cost deferrals	d	A	**(192)**	–
Storage and transportation deferrals	d	A	**(18)**	(10)
Deferred mark-to-market gains	d	A	–	(9)
Deferred income taxes (current)	e	A	–	(2)
Deferred income taxes (long-term)	e	B	**182**	189
Total regulatory liabilities			**(28)**	168

Financial Statement Location

(a) Accounts receivable
(b) Inventories
(c) Property, plant and equipment
(d) Accounts payable and accrued charges
(e) Deferred income taxes receivable/payable

Recovery/Settlement Period

(A) Remaining recovery / settlement is less than 1 year
(B) Remaining recovery / settlement is from 2 to 13 years
(C) Remaining recovery / settlement is over the remaining life of the associated assets

Gas cost deferrals

The Company operates under an OEB approved mechanism to change gas commodity rates on a quarterly basis to ensure that customers' rates reflect future expected prices based on published forward market prices. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers and is a component of the quarterly gas commodity rates. These amounts are subject to review and approval by the OEB typically on an annual basis. The regulatory asset or liability represents the difference between actual gas commodity costs incurred and the amount included in approved rates. In the absence of rate regulation, GAAP for non-regulated entities would require that actual commodity costs be recognized as an expense when incurred. After-tax earnings for 2006 would have been $142 million higher if these transactions were accounted for under GAAP for non-regulated entities.

Other deferrals

As prescribed by regulatory rate order, the Company has various amounts included in customer rates that are intended to recover identified costs. To the extent that the actual costs differ from actual revenues, the variance is deferred for future recovery from or refund to ratepayers. If the Company were not a regulated entity, after-tax earnings for 2006 would have been $10 million lower due to this deferral. In addition, GAAP for non-regulated entities would require that these costs be recognized as an expense when incurred.

Deferred mark-to-market gains/losses

The Company engages in hedging activity for the purpose of managing the risk associated with market fluctuations in the price of natural gas. Contracts that remain open at the balance sheet date are marked to market with an offsetting amount, representing an unrealized gain/loss, being deferred. If the Company were not a regulated entity, after-tax earnings for 2006 would have been $17 million lower, due to this deferral. In addition, GAAP for non-regulated entities would require that these unrealized gains/losses be recognized in income when incurred.

Gas in storage

Gas in storage is carried at the weighted average cost of gas ("WACOG") as approved by the OEB. In the absence of rate regulation, after-tax income would have been $96 million lower. In addition, GAAP for non-regulated entities would require that gas in storage be recorded at the lower of cost or market.

Deferred income taxes

As noted in note 1, the Company accounts for income taxes of its regulated operations using the flow through tax accounting methodology as approved by the OEB. Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Generally, rates and revenues for utility operations include recovery of only such income taxes as are currently payable. Accordingly, the Company does not provide for income taxes deferred to future years as a result of differences in the treatment for income tax and accounting purposes of various items of income and expenditure. In the absence of rate regulation, after-tax income would have been $7 million higher.

Asset removal costs

The Company has recorded a reduction to property, plant, and equipment as a result of removal costs for property that does not have an associated legal retirement obligation. In the absence of rate regulation, these costs would not have been recorded and net income after tax would have been $14 million lower.

Storage and transportation deferrals

The Company earns revenue for providing storage and transportation services to customers. The forecast of this revenue is one component used to establish Union's rates for services. Storage and transportation deferral accounts accumulate any difference between the actual revenue earned in providing these storage and transportation services and the forecast revenue approved by the OEB for rate making purposes. In the absence of rate regulation, GAAP for non-regulated entities would require that actual storage and transportation revenue be recognized in income when earned. Net income after tax would have been $5 million higher if these transactions were accounted for under GAAP for non-regulated entities. Based on the OEB's November 7, 2006 decision to deregulate a portion of Union's storage business serving ex-franchise markets, the use of storage deferral accounts related to long term storage sales is no longer required.

Property, plant and equipment

In the absence of rate regulation, property, plant and equipment would not have included overhead costs since some of these costs would have been charged to earnings in the period in which they occurred. As such, annual operating and maintenance costs would have been higher by the amounts capitalized and depreciation would be lower due to the impact of lower capitalized costs. These amounts are not readily determinable.

3. Cash, Cash Equivalents and Short-Term Borrowings

($millions)	**2006**	2005
Cash on hand and balances with banks	**(6)**	(156)
Short-term investments	**115**	2
	109	(154)

4. Accounts Receivable

($millions)	**2006**	2005
Trade	**336**	375
Gas imbalances (note 5)	**46**	25
Regulatory (note 2)	**43**	40
Other	**4**	23
	429	463

See note 20 for discussion of related party transactions.

5. Gas Imbalances

The Company, in the normal course of its operations experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the balance sheet dates. As the settlement of imbalances is in-kind, changes in the balances do not have an impact on the Company's cash flow from operating activities.

Accounts receivable and accounts payable include approximately $46 million and $25 million as of December 31, 2006 and 2005, respectively, related to gas imbalances and gas balancing services.

6. Inventories

($millions)	**2006**	2005
Gas in storage	**313**	282
Materials and supplies	**27**	25
	340	307

Gas in storage includes gas for delivery to customers and for use for the Company's own operating requirements. Inventories of materials and supplies are used in the operation and maintenance of the Company's system.

7. Property, Plant and Equipment

($millions)	**2006**	2005
Cost		
Distribution	**3,114**	2,976
Transmission	**1,286**	1,167
Storage	**655**	609
General	**257**	235
	5,312	4,987
Accumulated depreciation		
Distribution	**1,151**	1,111
Transmission	**435**	416
Storage	**247**	230
General	**103**	97
	1,936	1,854
Net book value	**3,376**	3,133

Property, plant and equipment are recorded net of contributions in aid of construction. Depreciation rates used during the year ended December 31, 2006 resulted in a composite rate of 3.28% (2005 – 3.37%).

Included in property, plant and equipment are the following:

($millions)	**2006**	2005
Assets not subject to depreciation [(a)]	**133**	151
Asset retirement cost	**20**	–
Interest charge capitalized during the year	**4**	2
Equipment under capital lease (net of accumulated amortization of $1 and $3 respectively)	**4**	2

(a) Assets not subject to depreciation include land, base pressure gas in storage reservoirs and assets under construction.

8. Investments and Other Assets

($millions)	**2006**	2005
Gas balancing for direct purchase customers [(a)]	**130**	130
Employee future benefits (note 18)	**84**	73
Deferred financing charges	**9**	9
Goodwill	**9**	9
Other	**3**	2
	235	223

(a) Bundled delivery service customers are required to balance their gas supply and gas consumption annually. To provide this service the Company owns gas to meet the customers' demand for gas during the year. This balancing gas is recorded at cost.

9. Short-term Borrowings

The Company has total bank lines of credit of $425 million (2005 - $325 million). The lines of credit include a committed credit facility of $400 million (2005 - $300 million) with a one-year term that commenced in June 2006, and a $25 million (2005 - $25 million) operating facility. During the term of the committed credit facility, the Company has the option to convert a portion of the drawings under the facility to loans not exceeding twelve months in duration. The bank lines of credit are unsecured.

These lines of credit enable the Company to borrow directly from banks, issue bankers' acceptances and support a commercial paper program. A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper at rates generally below the prime lending rate. The average interest rate on short-term borrowings for the year ended December 31, 2006 was 3.3% (2005 – 3.0%).

Total short-term interest paid in 2006 was less than $1 million (2005 – $1 million).

10. Accounts Payable and Accrued Charges

($millions)	**2006**	2005
Trade	**147**	172
Gas imbalances (note 5)	**46**	25
Regulatory (note 2)	**210**	19
Other	**273**	286
	676	502

See note 20 for discussion of related party transactions.

11. Long-term Debt and Obligation Under Capital Lease

($millions)		**2006**	2005
Sinking fund debentures			
11.55%	1988 Series II debentures, due October 15, 2010	**49**	53
13.50%	Senior debentures, due November 14, 2008	**4**	5
10.75%	Senior debentures, due July 31, 2009	**30**	33
Other long-term debt			
10.625%	1989 Series debentures, due July 11, 2011	**125**	125
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
7.90%	1994 Series II debentures, due February 24, 2014	**150**	150
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
7.80%	Senior debentures, due December 1, 2006	–	75
Medium-term note debentures			
5.70%	Series 1, due July 14, 2008	**100**	100
7.20%	Series 2, due June 1, 2010	**185**	185
6.65%	Series 3, due May 4, 2011	**250**	250
5.19%	Series 4, due December 17, 2007	**200**	200
4.64%	Series 5, due June 30, 2016	**200**	200
5.46%	Series 6, due September 11, 2036	**165**	–
4.85%	Series 7, due April 25, 2022	**125**	–
		2,183	1,976
Obligation under capital lease		**4**	5
		2,187	1,981
Less: current portion		**209**	84
		1,978	1,897

The Company's long-term debt is unsecured. The weighted average cost of long-term debt for the year ended December 31, 2006 was 7.7% (2005 – 7.8%). Principal repayment requirements on long-term debt are as follows:

($millions)	**Long-term debt**	**Obligation under capital lease**	**Total**
2007	208	1	209
2008	110	1	111
2009	28	2	30
2010	222	–	222
2011	375	–	375
Thereafter	1,240	–	1,240
Total	2,183	4	2,187

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2006, the Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2006 was $150 million (2005 - $157 million).

Total interest paid on the obligation under capital lease was less than $1 million in 2006 and 2005.

12. Mandatorily Redeemable Preference Shares

Authorized		**Outstanding 2006**	**Outstanding 2005**	**2006**	2005
(shares)		*(shares)*		*($millions)*	
Class A – 112,072	Series A, 5.5%	47,672	49,772	**3**	3
	Series C, 5.0%	49,500	49,500	**2**	2
				5	5
Less: current portion				**–**	–
				5	5

The Class A Preference Shares, Series A and C are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

13. Share Capital

	Authorized	Outstanding 2006	2005	2006	2005
	(shares)	*(shares)*		*($millions)*	
Class A, Series B, 6%	90,000	90,000	90,000	**5**	5
Class B, Series 11, 4.79%	Unlimited	4,000,000	4,000,000	**100**	100
				105	105
Common Shares	Unlimited	57,822,650	57,822,650	**627**	627
				732	732

The Class A Preference Shares, Series B are cumulative and redeemable at $55 per share.

The Series 11 Shares are cumulative and redeemable at the option of the Company and, at the option of the holders, convertible back into Series 10 Shares every five years commencing January 1, 2009.

14. Asset Retirement Obligation

The Company has a legal obligation to disconnect, purge and cap abandoned pipeline. The Company also has buildings that contain asbestos and therefore will have a legal obligation requiring the special handling and disposition of the asbestos if it is disturbed.

During the year, the Company recognized an ARO of $66 million related to the obligation to disconnect, purge and cap abandoned pipeline. In 2005 the liability was classified as a non-legal asset removal cost (note 2), a component of property plant and equipment. As such, the increase in the ARO in 2006 represents a non-cash transfer from property plant and equipment.

The Company has non-asbestos ARO which include storage wells, easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

At December 31, 2006, the estimated undiscounted cash flows required to settle the asset retirement obligations of the Company were $468 million (2005 – $1 million), calculated using an inflation rate of 2.0% per annum. The estimated fair value of this liability was $67 million (2005 – $1 million) after discounting the estimated cash flows at a rate of 5.5% per annum. At December 31, 2006, the timing of payment for settlement of the obligations ranges from 11 to 49 years.

Reconciliation of Asset Retirement Obligations:

($millions)	**2006**	2005
Balance, beginning of year	**1**	–
ARO recognized during the year	**66**	1
Balance, end of year	**67**	1

15. Stock-Based Compensation

Under the Long Term Incentive Share Option Plan 1989 ("1989 Plan"), the Company's parent company, Westcoast Energy Inc. ("Westcoast") has granted certain stock options to its employees, including employees of Union. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of Westcoast's shares on the date of grant.

Regular stock options vest in five equal stages with the first stage vesting immediately on the date of the grant and the remainder in four equal annual stages commencing on the first anniversary of the date of grant. Key employee retention stock options commence vesting two years after the date of issuance and then vest in three equal annual instalments. The maximum term of both stock options awarded under the 1989 Plan is ten years. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

Performance-based stock options commence vesting when a pre-determined performance threshold has been achieved. The options then vest in three equal annual stages commencing on the date the performance threshold is achieved. The maximum term for performance-based options awarded under the 1989 Plan ranges from five to eight years. Share appreciation rights have not been attached to performance-based options awarded under the 1989 Plan.

Under the terms of the acquisition of Westcoast by Duke Energy, all of the issued and outstanding stock options of Westcoast were exchanged for replacement options to purchase Duke Energy common shares at an exchange ratio specified in the purchase agreement. All terms and conditions of the replacement options were substantially the same as the terms and conditions of the options of Westcoast. For the year ended December 31, 2006, less than $1 million of compensation expense (2005 - less than $1 million) was attributable to the granting or exercise of the options attached to Duke Energy common shares by current and former employees of the Company.

Duke Energy's 1998 Long-term Incentive Plan ("1998 Plan"), as amended, reserved 60 million shares of common stock for awards to employees and outside directors. Under the 1998 Plan, the exercise price of each option granted cannot be less than the market price of Duke Energy's common stock on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to five years. There were no stock options granted under the 1998 Plan in 2006 or 2005.

A summary of the status of stock options held by employees of the Company as of December 31, 2006 and 2005, and changes during the years ended on those dates is presented below:

	2006		2005	
	Shares	**Weighted-Average Exercise Price US$**	Shares	Weighted-Average Exercise Price US$
Outstanding at beginning of year	**226,855**	**$23.85**	246,352	$24.04
Transfers in/(out)	**(7,133)**	**23.48**	31,468	22.09
Exercised	**(37,635)**	**20.12**	(20,422)	17.75
Forfeited	**-**	**-**	(30,543)	27.65
Outstanding at end of year	**182,087**	**$24.67**	226,855	$23.85
Options exercisable at year-end	**170,287**	**$25.43**	192,350	$24.65

	Options Outstanding			**Options Exercisable**	
Exercise Prices US$	Number Outstanding At 12/31/06	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price US$	Number Exercisable At 12/31/06	Weighted-Average Exercise Price US$
$13 – 15	33,550	6.2	$13.77	21,750	$13.77
$16 - 20	31,707	2.9	19.97	31,707	19.97
$21 – 25	25,137	2.8	21.71	25,137	21.71
$26 – 30	37,512	3.1	27.55	37,512	27.55
$31 – 34	52,181	4.3	33.39	52,181	33.39
> $34	2,000	5.3	37.80	2,000	37.80
Total	182,087	4.0	24.67	170,287	25.43

At December 31, 2006, 182,087 Duke Energy common shares were under option at prices ranging from US$13.77 to US$37.80 per share, of which 143,637 are eligible for share appreciation rights that allow the holder to receive 50% of the appreciated value in cash and the balance in common shares of Duke Energy.

The estimated fair value of these stock options was determined using the Black Scholes option pricing model using the following assumptions, resulting in a weighted-average fair value of $6.90 CDN ($4.58 USD).

Risk free interest rate	3.66%
Expected life (years)	7
Expected volatility	37.0%
Expected dividends	3.38%

The 1998 Plan allows for a maximum of twelve million shares of common stock to be issued under restricted stock awards, stock-based performance awards and phantom stock awards. Stock-based performance awards granted under the 1998 Plan generally vest over three year periods. Vesting can occur in three years if performance is met. Performance awards granted in 2006 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards with the adoption of CICA S.3870. The model uses three year historical volatilities and correlations for all companies in the pre-defined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant is incorporated within the model. Other awards not containing market conditions are measured at grant date price. Duke Energy awarded 23,100 shares (fair value of approximately $700,000) to employees of the Company in 2006 and 31,230 shares (fair value of approximately $800,000 at grant dates) to employees of the Company in 2005. Compensation expense for the performance awards is charged to earnings over the vesting period, and totalled less than $1 million for the Company in 2006 (2005 - less than $1 million).

Phantom stock awards granted under the 1998 Plan generally vest over five year periods. Duke Energy awarded 15,370 shares (fair value of approximately $400,000 at grant dates) to employees of the Company in 2006 and 24,970 shares (fair value of approximately $700,000 at grant dates) to employees of the Company in 2005. Compensation expense for the phantom awards is charged to earnings over the vesting period, and totalled less than $1 million for the Company in 2006 (2005 – less than $1 million).There were no restricted stock awards granted under the 1998 Plan during 2006 or 2005.

16. Risk Management

Natural Gas Risk Management Contracts

The Company is exposed to the impact of market fluctuations in the price of natural gas. The Company employs established policies and procedures to manage its risk associated with these market fluctuations by using various natural gas hedge contracts. These hedge contracts are recorded at market value within accounts receivable and accounts payable (notes 4 and 10). The realized benefits and costs of entering into these transactions are included as part of the commodity cost once the contract is settled.

As at December 31, 2006, the Company has a forecast gas supply of 114 PJs for the twelve months ending December 31, 2007. Approximately 79% of this forecasted gas supply is not currently hedged. The balance of the portfolio consists of fixed price contracts or has been effectively hedged through the use of financial options that mature prior to December 2007.

Credit Risk

Credit risk represents the loss that the Company would incur if a counterparty fails to perform under its contractual obligations. Where exposed to credit risk, the Company analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement amount of gas loans at December 31, 2006 was $79 million (2005 -

$58 million). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

17. Fair Values of Financial Assets and Liabilities

The Company records financial assets and liabilities at historical cost with the exception of natural gas swap contracts, which have been marked to market. Since the Company is a regulated utility, any gains or losses on natural gas swap contracts are deferred and reflected in future rates. Fair values, in the table below, have been estimated by reference to quoted market prices for the actual or similar instruments where available. The fair value of accounts receivable and current liabilities approximate their carrying amounts in the financial statements due to the relatively short period to maturity of these instruments. The carrying values and fair values of the Company's other financial instruments are as follows:

($millions)	**2006**		2005	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Assets				
Natural gas swap contracts	**(8)**	**(8)**	19	19
Liabilities				
Long-term debt (note 11)	**2,187**	**2,519**	1,976	2,356
Redeemable preference shares (note 12)	**5**	**5**	5	5

Under the regulatory process, the Company recovers the cost of natural gas, including swaps, and the weighted average cost of its long-term debt through its rate setting mechanism.

18. Employee Future Benefits

The Company sponsors five defined benefit registered pension plans and one registered pension plan with both a defined benefit provision and a defined contribution provision. Eligible employees of the Company participate in one of these registered pension plans. All of the defined benefit plans provide a final average earnings related benefit. The Company makes contributions to the defined contribution plan based on the salary, age and service of each member. Supplemental defined benefit pensions are provided to all employees affected by the maximum pension limits under the *Income Tax Act (Canada)*. Other post-retirement benefits provided include health and dental benefits and life insurance coverage.

Accrued benefit obligations are determined using the projected benefit method pro-rated on services. The Company uses a measurement date of September 30. In determining the accrued benefit obligations and current service costs, the Company uses management's best-estimate assumptions, except for the liability discount rate, which is determined as the yield on high quality fixed income investments with a term to maturity similar to the covered benefits.

Plan assets are valued at fair value. The calculation of the expected return on assets is based on a market related value of assets, with the market related adjustment determined over a three-year period.

The transitional obligation at January 1, 2000 is being amortized on a straight line basis over the expected average remaining service lifetime ("EARSL") of employees active at January 1, 2000. Past service costs arising from plan amendments are amortized on a straight-line basis over the average EARSL of employees active at the date of the amendment. The amount by which the net unamortized cumulative actuarial gain or loss exceeds 10% of the greater of the accrued benefit obligation and the market related value of assets at the beginning of the period is amortized on a straight-line basis over the EARSL of employees active at the beginning of the period. The average remaining service period of the active employees covered by the retirement plans is 10 years.

In 2006, the Company contributed $33 million (2005 – $35 million) to the defined benefit pension plans, $3 million (2005 – $2 million) to the defined contribution pension plan, $1 million (2005 – $1 million) to supplemental pension arrangements and $2 million (2005 – $3 million) for post-retirement benefits other than pensions.

Information about the defined benefit plans, in aggregate, for the years ended December 31, 2006 and 2005 is as follows:

	Pension		Other	
($millions)	**2006**	2005	**2006**	2005
Accrued benefit obligations				
Balance, beginning of year	**525**	431	**71**	58
Employer current service cost	**10**	8	**2**	1
Member contributions	**3**	3	**–**	–
Interest cost	**26**	26	**4**	4
Benefits paid	**(25)**	(25)	**(3)**	(3)
Actuarial (gain) loss	**13**	82	**(25)**	11
Balance, end of year	**552**	525	**49**	71
Plan assets				
Fair value, beginning of year	**405**	331	**–**	–
Actual return on plan assets	**25**	56	**–**	–
Employer contributions	**35**	40	**3**	3
Member contributions	**3**	3	**–**	–
Benefits paid	**(25)**	(25)	**(3)**	(3)
Fair value, end of year	**443**	405	**–**	–
Funded status				
Net funded status	**(109)**	(120)	**(49)**	(71)
Unamortized net actuarial loss	**150**	148	**4**	29
Unamortized past service costs	**10**	11	**–**	–
Unamortized transitional obligation	**13**	15	**14**	16
Contributions remitted after measurement date	**10**	11	**–**	1
Accrued benefit asset (liability)	**74**	65	**(31)**	(25)

($millions)	Pension 2006	Pension 2005	Other 2006	Other 2005
Classification of accrued benefit assets (liabilities)				
Deferred charges and other assets	**84**	73	**–**	–
Deferred credits and other liabilities	**(10)**	(8)	**(31)**	(25)
Accrued benefit asset (liability)	**74**	65	**(31)**	(25)

	Pension 2006	Pension 2005	Other 2006	Other 2005
Weighted average assumptions used to determine benefit liability				
Discount rate at measurement date	**5.00%**	5.00%	**5.00%**	5.00%
Rate of compensation increase	**3.50%**	3.25%	**3.50%**	3.25%

	Pension 2006	Pension 2005	Other 2006	Other 2005
Allocation of assets to major classes				
Equity securities	**59%**	67%	**–**	–
Debt securities	**41%**	33%	**–**	–

	Pension 2006	Pension 2005	Other 2006	Other 2005
Net benefit cost				
Current service cost	**10**	8	**2**	1
Interest cost	**26**	26	**4**	4
Actual return on plan assets	**(25)**	(56)	**–**	–
Actuarial (gains) losses	**13**	82	**(25)**	11
Amortization of transitional obligation	**2**	2	**2**	2
Past service cost	**–**	–	**–**	–
Difference between actual and expected return	**(2)**	32	**–**	–
Difference between actual and recognized actuarial gains (losses) in year	**–**	(75)	**25**	(10)
Difference between actual and recognized past service costs in year	**1**	1	**–**	–
Annual benefit plan cost	**25**	20	**8**	8
Defined contribution cost	**3**	2	**–**	–
Total net benefit cost	**28**	22	**8**	8

	Pension 2006	Pension 2005	Other 2006	Other 2005
Weighted average assumptions used to determine net benefit cost				
Discount rate	**5.00%**	6.25%	**5.00%**	6.25%
Expected rate of return on plan assets	**7.25%**	7.50%	**–**	–
Rate of compensation increases	**3.25%**	3.25%	**3.25%**	3.25%
Initial overall health care trend rate	–	–	**7.00%**	8.00%
Annual rate of decline in health care trend rate	–	–	**1.00%**	1.00%
Ultimate health care cost trend rate	–	–	**5.00%**	5.00%

An increase of 1% in the assumed health care trend rate would result in an increase of $4 million to the other employee future benefit obligation. A decrease of 1% in the assumed health care trend rate would result in a decrease of $3 million to the other employee future benefit obligation.

For 2006 and 2005, all of the defined benefit pension plans have accrued benefit obligations that exceed the fair value of plan assets. The other post-retirement benefit plans are not pre-funded.

19. Income Taxes

The provision for income taxes consists of the following:

($millions)	**2006**	2005
Current	**128**	30
Deferred	**(91)**	20
	37	50

The year-over-year change in the components of current and deferred income taxes is primarily due to the difference in the treatment of the approved cost and the actual cost of gas for income tax and accounting purposes.

Net income taxes paid in 2006 were $29 million (2005 - $29 million).

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

($millions)	**2006**	2005
Income before income taxes	**141**	171
Statutory income tax rate (percent)	**36.1**	36.1
Statutory income tax rate applied to accounting income	**51**	62
Increase (decrease) resulting from:		
Large corporations tax	–	6
Deductions claimed for income tax purposes lower than (in excess of) amounts recorded for accounting purposes	**(6)**	1
Recognition of long-term deferred tax liability associated with the OEB decision to deregulate gas storage services in Ontario (note 1)	**10**	–
Change in rate for long-term deferred income taxes	**2**	–
Amortization of deferred income taxes	**(20)**	(19)
Provision for income taxes	**37**	50
Effective rate of income tax (percent)	**26.2**	29.4

The deferred income taxes recorded in current assets of $71 million (2005 – current liabilities of $10 million) arise from temporary differences primarily related to regulatory deferral accounts.

The long-term deferred tax liability of $233 million at December 31, 2006 (2005 - $233 million) includes $19 million (2005 - $19 million) arising from temporary differences related to regulatory deferral accounts, and $10 million (2005 – nil) arising from temporary differences recognized as a result of the OEB decision on the regulation of gas storage services (note 1). The remaining $194 million (2005 -

$214 million) arose from using the tax allocation methodology related to utility operations prior to 1997. After 1997, the OEB required the use of the flow through method of accounting for taxes. As approved by the OEB, this balance of $194 million (2005 – $214 million) is reduced as the timing differences that gave rise to these deferred income taxes reverse. These timing differences are expected to fully reverse by 2018. Differences between the flow through method, used by the Company, and the liability method are as follows:

	Liability Method		Flow Through Method	
($millions)	**2006**	2005	**2006**	2005
Current deferred income tax asset	**73**	–	**71**	–
Current deferred income tax liability	–	8	–	10
Long-term deferred income tax liability	**405**	422	**223**	233
Recovery of deferred income tax	**98**	–	**91**	–
Deferred income tax expense	–	33	–	20

20. Related Party Transactions

The Company purchases gas and transportation services at prevailing market prices and under normal trade terms from commonly controlled companies. During the year ended December 31, 2006, these purchases totalled $10 million (2005 - $44 million). The Company also provides storage and transportation services to commonly controlled companies under normal trade terms. During the year, this revenue totalled less than $1 million (2005 - $5 million).

The Company provided administrative, management and other services to commonly controlled companies totalling $6 million (2005 - $6 million), which were recovered at cost. Charges from related parties for administrative and other goods and services were $12 million (2005 - $12 million).

At December 31, 2006 the Company has intercompany receivable balances of $1 million (2005 - $2 million) and intercompany payable balances of $1 million (2005 - $17 million), which are recorded in accounts receivable and accounts payable, respectively.

During the year, the Company obtained from and provided unsecured loans to its parent company, Westcoast. There was no balance outstanding on these loans at December 31, 2006 (2005 - $56 million payable). These loans are classified as short-term borrowings in 2005. Interest received on these loans was less than $1 million (2005 - $1 million) and the interest paid on these loans totalled less than $1 million in 2006 and 2005. Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

21. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. The Company has no reason to believe that the ultimate outcome of these matters would have a significant impact on its financial position, cash flows or results of operations.

Class Action Lawsuit

In 2004, the Company was served with two class action claims, seeking relief similar to a case filed against Enbridge Gas Distribution ("Enbridge"). In 1994, Enbridge, a gas distribution company located in Toronto, Ontario was served with a class action claim seeking, among other things, a declaration that the OEB-approved 5% late payment fee paid by Enbridge's customers since 1981 is interest that exceeds the amount permitted by the Criminal Code of Canada, and that by collecting the late payment fee, Enbridge had been unjustly enriched and those who paid the fee should be entitled to restitution. In December 2006 the court approved settlement of the claim commenced against Enbridge for $22 million, including $11 million in legal fees and expenses, $2 million that will be paid to the Class Proceedings fund (operated by the Law Foundation of Ontario) and a $9 million donation to the Winter Warmth Fund. The Company will participate in any OEB proceeding initiated by Enbridge to seek recovery of the settlement as it will establish an important precedent for the Company's ability to recover any settlement or liability with respect to Union's late payment class action.

By the date that the Company was served with the two class action claims, the structure of the OEB-approved late payment fees charged by the Company had changed from the 5% structure which was the subject of the two Supreme Court of Canada decisions. The Company has calculated the total amount of 5% late payment fees collected since 1994 to be up to $77 million. If the claimants were permitted to recover any portion of the amount claimed and the Company was required to refund the amount of such recovery, the Company would apply to the OEB to recover any amounts payable from ratepayers. Management is currently assessing the claims and anticipates that there will be no material financial impact on the Company from the ultimate resolution of those claims. However, if the claimants prevail, the cash outflows could occur in a different period than the requested recovery from ratepayers. As such, there could be a significant impact to the Company's cash flow from operating activities.

DIRECTORS

Martha B. Wyrsch
Chair

David G. Unruh(1)
Corporate Director

William C. Brown(1)
Corporate Director

Julie A. Dill
President

Arthur H. Willms(1)
Corporate Director

(1) *member of the Audit Committee*

OFFICERS

Julie A. Dill
President

Greg L. Ebel
Group Vice President and Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory Affairs and Economic Development

Bruce E. Pydee
Vice President, Government Relations and General Counsel

Bohdan I. Bodnar
Vice President, Human Resources

Menelaos Ydreos
Vice President, Operations and Distribution System Development

Stephen W. Baker
Vice President, Business Development and Commercial Accounts

Leigh Ann Shoji-Lee
Vice President

John McCraw
Vice President, Controller and Treasurer

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

Curt Bernardi
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar
CIBC Mellon

Union Gas Limited preference shares are listed on the Toronto Stock Exchange
Class A - 5½% (UNG.PR.C)

Class A – 6% (UNG.PR.D)

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ALLOCATION AND DISPOSITION OF 2006 DEFERRAL ACCOUNT BALANCES AND 2006 EARNINGS SHARING

The purpose of this evidence is to address the allocation and disposition of 2006 earnings sharing and 2006 deferral account balances not managed through the Quarterly Rate Adjustment Mechanism ("QRAM").

The allocation of 2006 deferral account balances and 2006 earnings sharing to rate classes appears at Tab 2, Schedule 1. The allocation of 2006 earnings sharing appears at Tab 2, Schedule 2. Tab 2, Schedule 3 provides the impact of the proposed dispositions per residential customer in the Southern Operations area and Northern and Eastern Operations area. It also provides the impact on the average customer taking service under Rate 10 in the Northern and Eastern Operations area. Appendix A summarizes the changes resulting from Union's proposals by rate class. Appendix B contains rate schedules reflecting the proposed dispositions. Appendix C provides the unit disposition rates for Union's in-franchise rate classes and summarizes the balances to be disposed of for Union's ex-franchise rate classes. Working Paper Schedule 1 shows the temporary commodity rate change applicable to the Southern Operations area.

2006 GAS SUPPLY-RELATED DEFERRAL ACCOUNTS

As indicated at Exhibit A, Tab 1, Union is seeking approval of final disposition of year-end balances for the gas cost related deferral accounts that are prospectively recovered through the QRAM process. For these accounts, recovery of the year-end deferral account balances will be managed through the QRAM process.

There are also two gas supply deferral accounts that are not recovered through the QRAM process. These are the Heating Value Deferral Account (179-89) and the Unabsorbed Demand Cost ("UDC") Deferral Account (179-108). For these accounts Union is seeking approval of the final disposition and recovery of the year-end balances.

Union proposes that the balance in the Heating Value Deferral Account (179-89) be allocated to the Rate 01 and Rate 10 customer classes in the Northern and Eastern Operations area in proportion to 2006 sales service, ABC-T and Bundled-T delivery volume respectively. The proposed method for allocating the heating value deferral account is consistent with that used by Union and approved by the Board in the past.

Union proposes that the portion of the balance in the Unabsorbed Demand Cost Variance Account (179-108) related to the Northern and Eastern Operations area be allocated to the firm Rate 01, Rate 10 and Rate 20 customers in proportion to 2004 excess peak over annual average. This allocation is consistent with allocation of UDC in approved 2004 rates (RP-2003-0063, Rate Order Working Papers, Schedule 27 page 3).

As indicated at Exhibit A, Tab 1, page 4, the UDC associated with the Southern Operations area is applicable to sales service customers only. Accordingly, Union proposes that the portion of the balance in the Unabsorbed Demand Cost Variance Account (179-108) related to the Southern Operations area be allocated to sales service customers only.

2006 NON- GAS SUPPLY RELATED DEFERRAL ACCOUNTS

Non-gas supply related deferral accounts can be divided into two groups: Storage and Transportation-related deferral accounts and Other deferral accounts.

STORAGE AND TRANSPORTATION RELATED DEFERRAL ACCOUNTS

The storage and transportation related deferral accounts are:

i) Transportation and Exchange Services Deferral Account (179-69)

ii) Short Term Storage and Other Balancing Services Deferral Account (179-70)

iii) Long Term Peak Storage Services Deferral Account (179-72)

iv) Other S&T Services Deferral Account (179-73)

v) Other Direct Purchase Services Deferral Account (179-74)

Transportation and Exchange Services Deferral Account (179-69)

Union proposes that firm C1 and M12 customers and in-franchise customers receive an allocation of the Transportation and Exchange Services Deferral Account (179-69) balance in proportion to actual 2006 available capacity. Further, Union proposes that the balance allocated to in-franchise customers in the Southern Operations area be allocated among rate classes in proportion to RP-2003-0063 design (peak) day demand. Union proposes that the balance allocated to customers in the Northern and Eastern Operations area (by virtue of their use of transportation systems in the Southern Operations area) be allocated among rate classes in proportion to the allocation of 2004 storage demand costs as approved in RP-2003-0063.

Short Term Storage and Other Balancing Services Deferral Account (179-70)

Union proposes to allocate the Short Term Storage and Other Balancing Services Deferral Account balance related to in-franchise customers in the Southern Operations area among rate classes in proportion to RP-2003-0063 design (peak) day demand. Union proposes to allocate the balance to in-franchise customers in the Northern and Eastern Operations area (by virtue of their use of storage in the Southern Operations area) among rate classes in proportion to the allocation of 2004 storage demand costs as approved in RP-2003-0063.

Long-Term Peak Storage Services Deferral Account (179-72), Other S&T Services Deferral Account (179-73) and Other Direct Purchase Services Deferral Account (179-74)

Union proposes to allocate the balance in the Long-Term Peak Storage Services Deferral Account (179-72), Other S&T Services Deferral Account (179-73) and Other Direct Purchase Services Deferral Account (179-74) to in-franchise rate classes in the Southern Operations area in proportion to RP-2003-0063 design (peak) day demand and in-franchise rate classes in the Northern and Eastern Operations area (by virtue of their use of storage in the Southern Operations area) in proportion to the allocation of 2004 storage demand costs as approved in RP-2003-0063.

OTHER DEFERRAL ACCOUNTS

Union proposes to allocate the balance in the Direct Purchase Revenue and Payments Deferral Account (179-60) to rate classes in the Southern Operations area in proportion to the 2004 approved Dawn-Trafalgar design day demand for in-franchise customers. This allocation is the same as that used to allocate the Delivery Commitment Credit ("DCC") amount approved in rates.

Union proposes to allocate the balance in the Lost Revenue Adjustment Mechanism Deferral Account (179-75) to rate classes in proportion to the margin reduction attributable to demand side management activities appearing at Exhibit A, Tab 1, Schedule 2, Page 1 of 5.

Union proposes to allocate the balance in the Intra-period WACOG Deferral Account (179-102) to rate classes in proportion to the approved 2004 allocation of the items that the intra-period WACOG change relate to (i.e. Unaccounted-For Gas ("UFG"), Compressor Fuel and Gas In Storage). The proposed method for allocating the intra-period WACOG deferral account is consistent with that used by Union and approved by the Board in the past.

Union proposes to allocate the balance in the Storage Rights Compensation Costs Deferral Account (179-110) to rate classes in proportion to the approved 2004 allocation of underground storage land rights. This allocation is the same as that used to allocate the amount approved in rates.

Union proposes to allocate the balance in the Demand Side Management ("DSM") Variance Account (179-111) to rate classes in proportion to the approved 2004 allocation of DSM costs. This allocation is the same as that used to allocate the amount approved in rates and is consistent with how funds are spent on demand side management programs.

Union proposes to allocate the balance in the Late Payment Penalty Litigation Deferral Account (179-113) to rate classes in proportion to the allocation of the 2004 delayed/late payment revenue.

Union proposes to allocate the balance in the Incremental OEB Cost Assessment Deferral Account (179-114) in proportion to the 2004 approved allocation of administrative costs within Admin and General Expenses. This allocation is the same as that used to allocate the amount approved in rates.

Union proposes to allocate the balance in the Shared Savings Mechanism Variance Account (179-115) to rate classes in proportion to the net TRC benefits attributable to the respective rate classes appearing at Exhibit A, Tab 1, Schedule 3. This is consistent with the settlement agreement approved by the Board in the EB-2006-0021 proceeding.

2006 EARNINGS SHARING

Union is proposing to allocate 2006 earnings sharing of $12.879 million to all rate classes based on the allocation of the 2004 Board approved return on equity[1]. The allocation of 2004 Board approved return on equity underpins 2006 approved rates. The allocation of 2006 earnings sharing appears at Tab 2, Schedule 2. Union's proposal to use the allocation of return on equity approved for 2004 to allocate earnings sharing related to 2006 is consistent with how Union allocated the 2005 earnings sharing.

[1] Using return on equity (ROE) as the allocator has the same effect as using rate base. ROE is allocated to rate classes in proportion to rate base.

DISPOSITION OF 2006 EARNING SHARING AND 2006 DEFERRAL ACCOUNTS BALANCES

For rate M2, Rate 01 and Rate 10 customers Union proposes to dispose of net 2006 earnings sharing and 2006 deferral account balances not managed through the QRAM process prospectively, over the July 1, 2007 to December 31, 2007 time period. The prospective refund / recovery approach proposed for rate M2, Rate 01 and Rate 10 customers is consistent with how Union has been refunding / recovering deferral account balances through the QRAM process.

For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of net 2006 earnings sharing and 2006 delivery-related deferral account balances as a one-time credit or charge. This approach is the same as that approved by Board for the disposition of 2005 earnings sharing and deferral account balances.

General Service customer impacts are presented at Tab 2, Schedule 3. For a residential customer with annual consumption of 2,600 m^3, the charge for the period July 1, 2007 to December 31, 2007 is \$3.06 in the Southern Operations area. This \$3.06 charge consists of a delivery-related charge of \$2.60 which appears at line 7, column (e) and a commodity charge of \$0.46 appearing at line 8, column (e). The commodity charge is related to the recovery of unabsorbed demand charge debits that apply to sales customers in the Southern Operations area. For a residential customer with annual consumption of 2,600 m^3, the credit for the period July 1, 2007 to December 31, 2007 is \$4.14 in the Northern and Eastern Operations area. The \$4.14 credit consists of the delivery-related charge of \$3.19 which appears at line 1, column (e) and the gas transportation credit of \$7.33 appearing at line 2, column (e). The gas transportation credit is related to the refund of unabsorbed demand charge credits and heating value credits. These gas transportation credits apply to the Northern and Eastern Operations area only.

UNION GAS LIMITED

Allocation of 2006 Deferral Account Balances and 2006 Earnings Sharing to Rate Classes

Line No.	Particulars	Acct No. (a)	Northern and Eastern Operations Area: Rate 01 ($000's) (b)	Rate 10 ($000's) (c)	Rate 20 ($000's) (d)	Rate 77 ($000's) (e)	Rate 100 ($000's) (f)	Rate 25 ($000's) (g)	Southern Operations Area: M2 ($000's) (h)	M4 ($000's) (i)	M5A ($000's) (j)	M7 ($000's) (k)	M9 ($000's) (l)	M10 ($000's) (m)	T1 ($000's) (n)	T3 ($000's) (o)	M12 ($000's) (p)	M13 ($000's) (q)	C1 ($000's) (r)	M16 ($000's) (s)	Total (1) ($000's) (t)
	Gas Supply Transportation-Related Deferrals:																				
1	Unabsorbed Demand Cost (UDC) Variance	179-108	(874)	(261)	(59)				481	5				0							(708)
2	Heating Value	179-89	(1,655)	(750)																	(2,405)
	Storage and Transportation-Related Deferrals:																				
3	Transportation and Exchange Services	179-69	(157)	(47)	(11)	-	(7)		(630)	(63)	(3)	(68)	(4)	(0)	(199)	(41)	(2,648)		(126)		(4,004)
4	Balancing & Short Term Storage Services	179-70	(2,860)	(854)	(194)	-	(129)		(10,957)	(1,098)	(53)	(1,181)	(61)	(3)	(3,462)	(711)	-	-	-	-	(21,565)
5	Long-Term Peak Storage Services	179-72	1,234	369	84	-	56		4,750	476	23	512	27	1	1,501	308					9,341
6	Other S&T Services	179-73	(52)	(15)	(3)	-	(2)		(198)	(20)	(1)	(21)	(1)	(0)	(63)	(13)					(390)
7	Other Direct Purchase Services	179-74	(49)	(15)	(3)	-	(2)		(190)	(19)	(1)	(20)	(1)	(0)	(60)	(12)					(373)
8	Total Gas Supply Transportation-Related		(4,412)	(1,574)	(187)	-	(85)	-	(6,744)	(719)	(35)	(779)	(40)	(2)	(2,283)	(469)	(2,648)	-	(126)	-	(20,104)
	Delivery-Related Deferrals:																				
9	Deferred Customer Rebates/Charges	179-26	-	-					-												-
10	Comprehensive Customer Information Program	179-56	-	-					-												-
11	Direct Purchase Revenue and Payments	179-60							(118)	(11)	(0)	(8)	(1)	(0)	(23)	(10)	-	-	-	-	(171)
12	Lost Revenue Adjustment Mechanism (2)	179-75	1,069	418	50	-	49	-	2,037	263	64	26	-	-	4	-	-	-	-	-	3,980
13	Intra-period WACOG	179-102	2,247	532	130	-	848		8,211	990	800	1,268	47	1	-	-	-	183	429	55	15,742
14	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-		-	-	-	-	-	-	-	-					-
15	Storage Rights Compensation Costs	179-110	54	16	4	-	3		299	17	7	13	2	-	77	19	-	-	-	-	511
16	Demand Side Management Variance Account	179-111	1,262	292	278	-	278		3,992	278	278	278	-	-	278	-	-	-	-	-	7,213
17	Gas Distribution Access Rule Costs	179-112	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
18	Late Payment Penalty Litigation	179-113	68	3	0	-	0	0	231	0	0	-	-	-	0	-	-	-	-	-	303
19	Incremental OEB Cost Assessment	179-114	273	27	11	0	21	7	933	30	19	26	1	0	64	8	118	-	3	0	1,541
20	Shared Savings Mechanism Variance Account	179-115	468	400	672	-	668		2,508	1,008	-	376	-	-	899	-	-	-	-	-	7,000
21	Total Delivery-Related		5,441	1,689	1,146	0	1,866	7	18,093	2,576	1,168	1,979	49	1	1,299	17	118	183	432	55	36,119
22	Total 2006 Deferral Account Disposition		1,029	115	959	0	1,781	7	11,349	1,857	1,133	1,200	8	(1)	(984)	(452)	(2,530)	183	306	55	16,016
23	Earnings Sharing for 2006		(2,458)	(402)	(131)	(0)	(331)	(124)	(6,028)	(242)	(149)	(212)	(9)	(1)	(443)	(70)	(2,240)	(2)	(32)	(3)	(12,879)
24	Grand Total		(1,429)	(287)	828	(0)	1,450	(117)	5,320	1,615	983	988	(1)	(1)	(1,427)	(522)	(4,770)	181	274	52	3,137

Notes:
(1) EB-2007-0598, Tab 1, Schedule 1
(2) Per Exhibit A, Tab 1, Schedule 2, Page 1 of 5, column (e)

UNION GAS LIMITED
Allocation of 2006 Earnings Sharing to Rate Classes

Line No.	Particulars	Rate Class	C2004 Return on Equity Allocation (1) ($000's)	2006 Earnings Sharing ($000's)
			(a)	(b)
	Northern & Eastern Operations Area			
1	Small volume general service	01	50,591	(2,458)
2	Large volume general service	10	8,275	(402)
3	Medium volume firm service	20	2,694	(131)
4	Large volume high load factor	100	6,820	(331)
5	Large volume interruptible	25	2,556	(124)
6	Wholesale transportation	77	10	(0)
7	Total Northern & Eastern Operations Area		70,946	(3,447)
	Southern Operations Area			
8	General service	M2	124,089	(6,028)
9	Firm comm/ind contract	M4	4,979	(242)
10	Interruptible comm/ind contract	M5A	3,076	(149)
11	Seasonal comm/ind contract	M6A	-	-
12	Special large volume contract:	M7	4,365	(212)
13	Large wholesale service	M9	189	(9)
14	Small wholesale service	M10	11	(1)
15	Total Bundled Service		136,709	(6,642)
	Contract Carriage			
	Storage and transportation:			
16	Contract carriage service	T1	9,110	(443)
17	Wholesale service	T3	1,451	(70)
18	Total contract carriage		10,561	(513)
19	Total in-franchise service		147,270	(7,155)
	Storage and Transportation			
20	Cross franchise service	C1	658	(32)
21	Dawn-Trafalgar service	M12	46,116	(2,240)
22	Transportation of local production	M13	42	(2)
23	Storage Transportation service	M16	61	(3)
24	Total storage and transportation		46,877	(2,277)
25	Total Southern Operations Area		194,147	(9,432)
26	Total (line 7 + line 25)		265,093	(12,879) (2)

Notes: (1) Allocated costs per 2004 Decision
(2) EB-2007-0598, Tab 1, Schedule 3, line 13 (a)

UNION GAS LIMITED
General Service Bill Impacts
2006 Deferral Account and 2006 Earnings Sharing Disposition

Line No.	Particulars	Rate Component	Balance for Disposition ($000's) (1) (a)		Forecast Volume (10*3m*3) (2) (b)	Unit Rate for Prospective Recovery (cents/m*3) (c)	Volume (m*3) (3) (d)	Bill Impact ($) (e) = (c*d) / 100
1	Rate 01	Delivery	1,100		349,669	0.3146	1,013	3.19
2		Transportation	(2,529)	(4)	349,669	(0.7232)	1,013	(7.33)
3			(1,429)			(0.4086)		(4.14)
4	Rate 10	Delivery	724		155,907	0.4646	38,833	180.43
5		Transportation	(1,011)	(5)	154,329	(0.6551)	38,833	(254.39)
6			(287)			(0.1905)		(73.96)
7	Rate M2 Residential	Delivery	4,839		1,543,695	0.3135	829	2.60
8		Commodity	481		874,823	0.0549	829	0.46
9			5,320			0.3684		3.06
10	Rate M2 Commercial/ Industrial	Delivery				0.3135	5,559	17.43
11		Commodity				0.0549	5,559	3.05
12						0.3684		20.48

Notes:
(1) Includes the 2006 deferral account balances and 2006 Earnings Sharing.
(2) July 1 to December 31, 2007 forecast volumes.
(3) Average consumption, per customer, for the period July 1 to December 31, 2007.
(4) Tab 2, Schedule 1, Column (b), Line 1 + Line 2.
(5) Tab 2, Schedule 1, Column (c), Line 1 + Line 2.

Summary of Changes to Sales Rates

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 01A - Small Volume General Firm Service

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
1	Monthly Charge - All Zones	$16.00		$16.00
	Monthly Delivery Charge - All Zones			
2	First 100 m3	9.2380		9.2380
3	Next 200 m3	8.6369		8.6369
4	Next 200 m3	8.2100		8.2100
5	Next 500 m3	7.8180		7.8180
6	Over 1,000 m3	7.4944		7.4944
7	Delivery - Price Adjustment (All Volumes)		0.3146	0.3146 (1)
	Gas Transportation Service			
8	Fort Frances	2.8784		2.8784
9	Western Zone	2.8894		2.8894
10	Northern Zone	3.4791		3.4791
11	Eastern Zone	3.9849		3.9849
12	Transportation - Price Adjustment (All Zones)	(0.1281) (2)	(0.7232)	(0.8513) (3)
	Storage Service			
13	Fort Frances	1.9099		1.9099
14	Western Zone	1.9075		1.9075
15	Northern Zone	2.2951		2.2951
16	Eastern Zone	2.6079		2.6079
17	Storage - Price Adjustment (All Zones)	(0.0163) (4)		(0.0163) (5)
	Commodity Cost of Gas and Fuel			
18	Fort Frances	31.7996		31.7996
19	Western Zone	32.1383		32.1383
20	Northern Zone	32.5935		32.5935
21	Eastern Zone	32.9687		32.9687
22	Commodity and Fuel - Price Adjustment (All Zones)	(9.8875) (6)		(9.8875) (7)

Notes:
(1) Includes a temporary charge of 0.3146 cents/m^3 for the period July 1 to December 31, 2007.
(2) Includes Prospective Recovery of (0.1187), 0.0122, (0.0796) and 0.0580 cents/m^3.
(3) Includes Prospective Recovery of (0.1187), 0.0122, (0.0796), 0.0580 and a temporary credit of (0.7232) cents/m^3 for the period Jul 1-Dec 31, 2007.
(4) Includes Prospective Recovery of 0.0028, (0.0021), (0.0029) and (0.0141) cents/m^3.
(5) Includes Prospective Recovery of 0.0028, (0.0021), (0.0029) and (0.0141) cents/m^3.
(6) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.
(7) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 10 - Large Volume General Firm Service

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate	Rate Change	EB-2007-0598 Approved July 1, 2007 Rate
		(a)	(b)	(c)
1	Monthly Charge - All Zones	$70.00		$70.00
	Monthly Delivery Charge - All Zones			
2	First 1,000 m3	7.3562		7.3562
3	Next 9,000 m3	5.8543		5.8543
4	Next 20,000 m3	4.9979		4.9979
5	Next 70,000 m3	4.4495		4.4495
6	Over 100,000 m3	2.3725		2.3725
7	Delivery - Price Adjustment (All Volumes)		0.4646	0.4646 (1)
	Gas Transportation Service			
8	Fort Frances	2.6378		2.6378
9	Western Zone	2.6488		2.6488
10	Northern Zone	3.2384		3.2384
11	Eastern Zone	3.7443		3.7443
12	Transportation - Price Adjustment (All Zones)	(0.1124) (2)	(0.6551)	(0.7675) (3)
	Storage Service			
13	Fort Frances	1.2255		1.2255
14	Western Zone	1.2231		1.2231
15	Northern Zone	1.6107		1.6107
16	Eastern Zone	1.9235		1.9235
17	Storage - Price Adjustment (All Zones)	(0.0275) (4)		(0.0275) (5)
	Commodity Cost of Gas and Fuel			
18	Fort Frances	31.7996		31.7996
19	Western Zone	32.1383		32.1383
20	Northern Zone	32.5935		32.5935
21	Eastern Zone	32.9687		32.9687
22	Commodity and Fuel - Price Adjustment (All Zones)	(9.8875) (6)		(9.8875) (7)

Notes:
(1) Includes a temporary charge of 0.4646 cents/m^3 for the period July 1 to December 31, 2007.
(2) Includes Prospective Recovery of (0.1078), 0.0129, (0.0779) and 0.0604 cents/m^3.
(3) Includes Prospective Recovery of (0.1078), 0.0129, (0.0779), 0.0604 and a temporary credit of (0.6551) cents/m^3 for the period Jul 1-Dec 31, 2007.
(4) Includes Prospective Recovery of (0.0030), (0.0052), (0.0043) and (0.0150) cents/m^3.
(5) Includes Prospective Recovery of (0.0030), (0.0052), (0.0043) and (0.0150) cents/m^3.
(6) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.
(7) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 20 - Medium Volume Firm Service

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
1	Monthly Charge	$780.00		$780.00
	Delivery Demand Charge			
2	First 70,000 m*3	20.3317		20.3317
3	All over 70,000 m*3	11.9561		11.9561
	Delivery Commodity Charge			
4	First 852,000 m*3	0.2877		0.2877
5	All over 852,000 m*3	0.2131		0.2131
	Monthly Gas Supply Demand Charge			
6	Fort Frances	24.4742		24.4742
7	Western Zone	24.7073		24.7073
8	Northern Zone	41.3066		41.3066
9	Eastern Zone	55.1752		55.1752
10	Gas Supply Demand - Price Adjustment (All Zones)	0.7275 (1)		0.7275 (2)
	Commodity Transportation 1			
11	Fort Frances	2.1365		2.1365
12	Western Zone	2.1400		2.1400
13	Northern Zone	2.5308		2.5308
14	Eastern Zone	2.8583		2.8583
15	Transportation 1 - Price Adjustment (All Zones)	(0.2215) (3)		(0.2215) (4)
	Commodity Transportation 2			
16	Fort Frances	0.1259		0.1259
17	Western Zone	0.1236		0.1236
18	Northern Zone	0.1909		0.1909
19	Eastern Zone	0.2508		0.2508
	Commodity Cost of Gas and Fuel			
20	Fort Frances	32.1780		32.1780
21	Western Zone	32.5207		32.5207
22	Northern Zone	32.9813		32.9813
23	Eastern Zone	33.3611		33.3611
24	Commodity and Fuel - Price Adjustment (All Zones)	(9.8875) (5)		(9.8875) (6)
	Bundled Storage Service ($/GJ)			
25	Monthly Demand Charge	11.289		11.289
26	Commodity Charge	0.240		0.240
27	Storage Demand - Price Adjustment	(0.389) (7)		(0.389) (8)

Notes:
(1) Includes Prospective Recovery of 0.2276, 0.1426, 0.3066 and 0.0507 cents/m^3.
(2) Includes Prospective Recovery of 0.2276, 0.1426, 0.3066 and 0.0507 cents/m^3.
(3) Includes Prospective Recovery of (0.1693), 0.0053, (0.0918) and 0.0343 cents/m^3.
(4) Includes Prospective Recovery of (0.1693), 0.0053, (0.0918) and 0.0343 cents/m^3.
(5) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.
(6) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.
(7) Includes Prospective Recovery of (0.051), (0.070), (0.119) and (0.149) $/GJ.
(8) Includes Prospective Recovery of (0.051), (0.070), (0.119) and (0.149) $/GJ.

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 100 - Large Volume High Load Factor Firm Service

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
1	Monthly Charge	$780.00		$780.00
	Delivery Demand Charge			
2	All Zones	11.9268		11.9268
	Delivery Commodity Charge			
3	All Zones	0.2102		0.2102
	Monthly Gas Supply Demand Charge			
4	Fort Frances	39.1286		39.1286
5	Western Zone	39.4005		39.4005
6	Northern Zone	58.7664		58.7664
7	Eastern Zone	74.9465		74.9465
	Commodity Transportation 1			
8	Fort Frances	3.7489		3.7489
9	Western Zone	3.7515		3.7515
10	Northern Zone	4.0447		4.0447
11	Eastern Zone	4.2903		4.2903
	Commodity Transportation 2			
12	Fort Frances	0.1259		0.1259
13	Western Zone	0.1236		0.1236
14	Northern Zone	0.1909		0.1909
15	Eastern Zone	0.2508		0.2508
	Commodity Cost of Gas and Fuel			
16	Fort Frances	32.1780		32.1780
17	Western Zone	32.5207		32.5207
18	Northern Zone	32.9813		32.9813
19	Eastern Zone	33.3611		33.3611
20	Commodity and Fuel - Price Adjustment (All Zones)	(9.8875) (1)		(9.8875) (2)
	Bundled Storage Service ($/GJ)			
21	Monthly Demand Charge	11.289		11.289
22	Commodity Charge	0.240		0.240
23	Storage Demand - Price Adjustment	(0.389) (3)		(0.389) (4)

Notes:
(1) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.
(2) Includes Prospective Recovery of (3.1202), (3.0312), (2.7354) and (1.0007) cents/m^3.
(3) Includes Prospective Recovery of (0.051), (0.070), (0.119) and (0.149) $/GJ.
(4) Includes Prospective Recovery of (0.051), (0.070), (0.119) and (0.149) $/GJ.

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate	Rate Change	EB-2007-0598 Approved July 1, 2007 Rate
		(a)	(b)	(c)
	Rate 25 - Large Volume Interruptible Service			
1	Monthly Charge	$190.00		$190.00
	Delivery Charge - All Zones *			
2	Maximum	4.5768		4.5768
	Gas Supply Charges - All Zones			
3	Minimum	14.3135		14.3135
4	Maximum	140.5622		140.5622
	Rate 77 - Wholesale Transportation Service			
5	Monthly Charge	$145.00		$145.00
6	Delivery Demand Charge - All Zones	28.2927		28.2927

* see Appendix C

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
	Utility Sales			
1	Commodity and Fuel	32.9687		32.9687
2	Commodity and Fuel - Price Adjustment	(7.0866) (1)	0.0549	(7.0317) (2)
3	Transportation	3.6279		3.6279
4	Total Gas Supply Commodity Charge	29.5100	0.0549	29.5649
	M4 Firm Commercial/Industrial			
5	Minimum annual gas supply commodity charge	5.5663		5.5663
	M5A Interruptible Commercial/Industrial			
6	Minimum annual gas supply commodity charge	5.5663		5.5663
	Storage and Transportation Supplemental Services - Rate T1 & T3	$/GJ		$/GJ
	Monthly demand charges: ($/GJ)			
7	Firm gas supply service	28.065		28.065
8	Firm backstop gas	4.245		4.245
	Commodity charges:			
9	Gas supply	8.788		8.788
10	Backstop gas	11.727		11.727
11	Reasonable Efforts Backstop Gas	11.404		11.404
12	Supplemental Inventory	Note (3)		Note (3)
13	Supplemental Gas Sales Service (cents/m^3)	46.4836		46.4836
14	Failure to Deliver	3.011		3.011
15	Discretionary Gas Supply Service (DGSS)	Note (4)		Note (4)

Notes:
(1) Includes Prospective Recovery of (2.0812), (2.5373), (1.2473) and (1.2208) cents/m^3.
(2) Includes Prospective Recovery of (2.0812), (2.5373), (1.2473) and (1.2208)and a temporary charge of 0.0549 for the period Jul 1-Dec 31, 2007.
(3) The charge for banked gas purchases shall be the higher of the daily spot gas cost at Dawn in the month of or the month following the month in which gas is sold under this rate and shall not be less than Union's approved weighted avg. cost of gas.
(4) Reflects the "back to back" price plus gas supply administration charge.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
	M2 General Service Rate			
1	Monthly Charge	$16.00		$16.00
	Monthly delivery commodity charge:			
2	First 1 400 m^3	5.1701		5.1701
3	Next 4 600 m^3	4.1427		4.1427
4	Next 124 000 m^3	3.0859		3.0859
5	Next 270 000 m^3	2.4743		2.4743
6	All over 400 000 m^3	2.2978		2.2978
7	Delivery - Price Adjustment (All Volumes)	(0.0941) (1)	0.3135	0.2194 (2)
8	Storage Service	0.9309		0.9309
	M4 Firm comm/ind contract rate			
	Monthly demand charge:			
9	First 8 450 m^3	45.6744		45.6744
10	Next 19 700 m^3	19.8165		19.8165
11	All over 28 150 m^3	16.4565		16.4565
	Monthly delivery commodity charge:			
12	First block	0.9291		0.9291
13	All remaining use	0.5089		0.5089
14	Delivery - Price Adjustment (All Volumes)	(0.1282) (3)		(0.1282) (4)
15	Minimum annual delivery commodity charge	1.2464		1.2464
	M5A interruptible comm/ind contract			
	Firm contracts *			
16	Monthly demand charge	27.5785		27.5785
17	Monthly delivery commodity charge	1.7957		1.7957
18	Delivery - Price Adjustment (All Volumes)	(0.0603) (5)		(0.0603) (6)
	Interruptible contracts *			
19	Monthly Charge	$500.00		$500.00
	Daily delivery commodity charge:			
20	4 800 m^3 to 17 000 m^3	1.9019		1.9019
21	17 000 m^3 to 30 000 m^3	1.7720		1.7720
22	30 000 m^3 to 50 000 m^3	1.7037		1.7037
23	50 000 m^3 to 70 000 m^3	1.6558		1.6558
24	70 000 m^3 to 100 000 m^3	1.6215		1.6215
25	100 000 m^3 to 140 870 m^3	1.5878		1.5878
26	Delivery - Price Adjustment (All Volumes)	(0.0603) (5)		(0.0603) (6)
27	Annual minimum delivery commodity charge	2.2192		2.2192

Notes:
(1) Includes Prospective Recovery of (0.0855), (0.0028), (0.0031) and (0.0027) cents/m^3.
(2) Includes Prospective Recovery of (0.0855), (0.0028), (0.0031), (0.0027) and a temporary charge of 0.3135 for the period Jul 1-Dec 31, 2007.
(3) Includes Prospective Recovery of (0.1300), (0.0008), 0.0020 and 0.0006 cents/m^3.
(4) Includes Prospective Recovery of (0.1300), (0.0008), 0.0020 and 0.0006 cents/m^3.
(5) Includes Prospective Recovery of (0.0700), 0.0009, 0.0043 and 0.0045 cents/m^3 associated with load balancing costs.
(6) Includes Prospective Recovery of (0.0700), 0.0009, 0.0043 and 0.0045 cents/m^3 associated with load balancing costs.

* Price changes to individual M5A firm and interruptible contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m³)	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
	M7 Special large volume contract			
	Firm			
1	Monthly demand charge	25.5426		25.5426
2	Monthly delivery commodity charge	0.3344		0.3344
3	Delivery - Price Adjustment	(0.0332) (1)		(0.0332) (2)
	Interruptible *			
	Monthly delivery commodity charge:			
4	Maximum	2.7337	-	2.7337
5	Delivery - Price Adjustment	(0.0332) (1)		(0.0332) (2)
	Seasonal *			
	Monthly delivery commodity charge:			
6	Maximum	2.4896		2.4896
7	Delivery - Price Adjustment	(0.0332) (1)		(0.0332) (2)
	M9 Large wholesale service			
8	Monthly demand charge	17.0902		17.0902
9	Monthly delivery commodity charge	0.5367		0.5367
10	Delivery - Price Adjustment	(0.1358) (3)		(0.1358) (4)
	M10 Small wholesale service			
11	Monthly delivery commodity charge	2.6978		2.6978

Notes:
(1) Includes Prospective Recovery of (0.1107), 0.0126, 0.0431 and 0.0218 cents/m³.
(2) Includes Prospective Recovery of (0.1107), 0.0126, 0.0431 and 0.0218 cents/m³.
(3) Includes Prospective Recovery of (0.1123), (0.0019), (0.0066) and (0.0150) cents/m³.
(4) Includes Prospective Recovery of (0.1123), (0.0019), (0.0066) and (0.0150) cents/m³.

* Price changes to individual interruptible and seasonal contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Contract Carriage Rates

Line No.	Particulars	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
	Contract Carriage Service			
	T1 Storage and Transportation			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.010		0.010
	Firm Injection/Withdrawal Right			
2	Union provides deliverability inventory	1.980		1.980
3	Customer provides deliverability inventory	1.050		1.050
4	Firm incremental injection	1.050		1.050
5	Interruptible withdrawal	1.050		1.050
	Commodity charges:			
6	Withdrawal	0.064		0.064
7	Customer provides compressor fuel	0.007		0.007
8	Injection	0.064		0.064
9	Customer provides compressor fuel	0.007		0.007
10	Storage fuel ratio - customer provides fuel	0.600%		0.600%
	Transportation (cents / m^3)			
11	Monthly demand charge first 140,870 m*3	18.9471		18.9471
12	Monthly demand charge all over 140,870 m*3	12.9470		12.9470
	Commodity charges:			
13	Firm- Union provides compressor fuel first 2,360,653 m*3	0.3573		0.3573
14	Union provides compressor fuel all over 2,360,653 m*3	0.2767		0.2767
15	Customer provides compressor fuel first 2,360,653 m*3	0.1604		0.1604
16	Customer provides compressor fuel all over 2,360,653 m*3	0.0798		0.0798
	Interruptible: *			
17	Maximum - Union provides compressor fuel	2.7337		2.7337
18	Maximum - customer provides compressor fuel	2.5368		2.5368
19	Transportation fuel ratio - customer provides fuel	0.554%		0.554%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges			
20	Injection May 1 to Oct 31	0.169		0.169
21	Customer provides compressor fuel	0.072		0.072
22	Withdrawals Nov 1 to Apr 30	0.169		0.169
23	Customer provides compressor fuel	0.072		0.072
24	Transportation commodity charge (cents / m^3)	0.9803		0.9803
25	Customer provides compressor fuel	0.7833		0.7833
26	Monthly Charge	$1,800		$1,800

* Price changes to individual interruptible and seasonal contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Contract Carriage Rates

Line No.	Particulars	EB-2007-0053 Approved April 1, 2007 Rate (a)	Rate Change (b)	EB-2007-0598 Approved July 1, 2007 Rate (c)
	T3 Storage and Transportation			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.010		0.010
	Firm Injection/Withdrawal Right			
2	Union provides deliverability inventory	1.980		1.980
3	Customer provides deliverability inventory	1.050		1.050
4	Firm incremental injection	1.050		1.050
5	Interruptible withdrawal	1.050		1.050
	Commodity charges:			
6	Withdrawal	0.064		0.064
7	Customer provides compressor fuel	0.007		0.007
8	Injection	0.064		0.064
9	Customer provides compressor fuel	0.007		0.007
10	Storage fuel ratio- Cust. provides fuel	0.600%		0.600%
	Transportation (cents / m^3)			
11	Monthly demand charge	9.0121		9.0121
	Commodity charges			
12	Firm- Union supplies compressor fuel	0.3242		0.3242
13	Customer provides compressor fuel	0.0666		0.0666
14	Transportation fuel ratio- Cust. provides fuel	0.725%		0.725%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
15	Injection	0.169		0.169
16	Customer provides compressor fuel	0.072		0.072
17	Withdrawals	0.169		0.169
18	Customer provides compressor fuel	0.072		0.072
19	Transportation commodity charge (cents / m^3)	0.6205		0.6205
20	Customer provides compressor fuel (cents / m^3)	0.3629		0.3629
	Monthly Charge			
21	City of Kitchener	$17,155		$17,155
22	Natural Resource Gas	$2,631		$2,631
23	Six Nations	$877		$877

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Unbundled Rates

Line No.	Particulars	EB-2007-0053 Approved April 1, 2007 Rate	Rate Change	EB-2007-0598 Approved July 1, 2007 Rate
		(a)	(b)	(c)
	U2 Unbundled Customers			
	Storage ($ / GJ)			
	Monthly demand charges:			
	Standard Storage Service (SSS)			
1	Combined Firm Space & Deliverability	0.021		0.021
	Standard Peaking Service (SPS)			
2	Combined Firm Space & Deliverability	0.106		0.106
3	Incremental firm injection right	0.955		0.955
4	Incremental firm withdrawal right	0.955		0.955
	Commodity charges:			
5	Injection customer provides compressor fuel	0.015		0.015
6	Withdrawal customer provides compressor fuel	0.015		0.015
7	Storage fuel ratio - Customer provides fuel	0.600%		0.600%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
8	Injection customer provides compressor fuel	0.046		0.046
9	Withdrawal customer provides compressor fuel	0.046		0.046
	U5 Unbundled Customers			
	Storage ($ / GJ)			
	Monthly demand charges:			
10	Combined Firm Space & Deliverability	0.021		0.021
11	Incremental firm injection right	0.955		0.955
12	Incremental firm withdrawal right	0.955		0.955
	Commodity charges:			
13	Injection customer provides compressor fuel	0.015		0.015
14	Withdrawal customer provides compressor fuel	0.015		0.015
15	Storage fuel ratio - Customer provides fuel	0.600%		0.600%
	Delivery (cents / m^3)			
	Firm contracts			
16	Monthly demand charge	21.8236		21.8236
17	Monthly delivery commodity charge	1.7957		1.7957
18	Transportation fuel ratio - Customer provides fuel	0.554%		0.554%
	Interruptible contracts			
19	Monthly Charge	$500.00		$500.00
	Monthly delivery commodity charge:			
20	4 800 m^3 to 17 000 m^3	1.5464		1.5464
21	17 000 m^3 to 30 000 m^3	1.4165		1.4165
22	30 000 m^3 to 50 000 m^3	1.3482		1.3482
23	50 000 m^3 to 70 000 m^3	1.3003		1.3003
24	70 000 m^3 to 100 000 m^3	1.2660		1.2660
25	100 000 m^3 to 140 870 m^3	1.2323		1.2323
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
26	Injection customer provides compressor fuel	0.046		0.046
27	Withdrawal customer provides compressor fuel	0.046		0.046

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Unbundled Rates

Line No.	Particulars	EB-2007-0053 Approved April 1, 2007 Rate	Rate Change	EB-2007-0598 Approved July 1, 2007 Rate
		(a)	(b)	(c)
	U7 Unbundled Customers			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Combined Firm Space & Deliverability	0.021		0.021
2	Incremental firm injection right	0.955		0.955
3	Incremental firm withdrawal right	0.955		0.955
	Commodity charges:			
4	Injection customer provides compressor fuel	0.015		0.015
5	Withdrawal customer provides compressor fuel	0.015		0.015
6	Storage fuel ratio - Customer provides fuel	0.600%		0.600%
	Delivery (cents / m^3)			
7	Monthly demand charge first 140,870 m*3	18.9471		18.9471
8	Monthly demand charge all over 140,870 m*3	12.9470		12.9470
	Commodity charges			
9	Firm Customer provides compressor fuel first 2,360,653 m*3	0.1604		0.1604
10	Firm Customer provides compressor fuel all over 2,360,653 m*3	0.0798		0.0798
	Interruptible:			
11	Maximum customer provides compressor fuel	2.5368		2.5368
12	Transportation fuel ratio - Customer provides fuel	0.554%		0.554%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
13	Injection customer provides compressor fuel	0.046		0.046
14	Withdrawal customer provides compressor fuel	0.046		0.046
15	Transportation commodity charge (cents / m*3)	0.7833		0.7833
	Other Services & Charges			
16	Monthly Charge	$1,800		$1,800

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Unbundled Rates

Line No.	Particulars	EB-2007-0053 Approved April 1, 2007 Rate	Rate Change	EB-2007-0598 Approved July 1, 2007 Rate
		(a)	(b)	(c)
	U9 Unbundled Customers			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.021		0.021
2	Incremental firm injection right	0.955		0.955
3	Incremental firm withdrawal right	0.955		0.955
	Commodity charges:			
4	Injection customer provides compressor fuel	0.015		0.015
5	Withdrawal customer provides compressor fuel	0.015		0.015
6	Storage fuel ratio - Customer provides fuel	0.600%		0.600%
	Delivery (cents / m^3)			
7	Monthly demand charge	9.0121		9.0121
	Commodity charges			
8	Firm customer provides compressor fuel	0.0666		0.0666
9	Transportation fuel ratio - Customer provides fuel	0.725%		0.725%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
10	Injection customer provides compressor fuel	0.046		0.046
11	Withdrawal customer provides compressor fuel	0.046		0.046
12	Transportation commodity charge (cents / m^3)	0.3629		0.3629
	Other Services & Charges			
	Monthly Charge			
13	City of Kitchener	$17,155		$17,155
14	NRG	$2,631		$2,631
15	Six Nations	$877		$877

Rate Schedules

(Rate 01, Rate 10, Rate M2, and Schedule A by operating area)

uniongas

Union Gas Limited
Northern and Eastern Operations Area
Gas Supply Charges

(A) Availability

Available to customers in Union's Fort Frances, Western, Northern and Eastern Delivery Zones.

(B) Applicability:

To all sales customers served under Rate 01A, Rate 10, Rate 20, Rate 100 and Rate 25.

(C) Rates

Utility Sales

Rate 01A (cents / m^3)

Effective July 1, 2007

	Fort Frances	Western	Northern	Eastern
Storage	1.9099	1.9075	2.2951	2.6079
Storage - Price Adjustment (1)	(0.0163)	(0.0163)	(0.0163)	(0.0163)
Commodity and Fuel	31.7996	32.1383	32.5935	32.9687
Commodity and Fuel - Price Adjustment (1)	(9.8875)	(9.8875)	(9.8875)	(9.8875)
Transportation	2.8784	2.8894	3.4791	3.9849
Transportation - Price Adjustment (1)	(0.8513)	(0.8513)	(0.8513)	(0.8513)
Total Gas Supply Charge	25.8328	26.1801	27.6126	28.8064

Rate 10 (cents / m^3)

Effective July 1, 2007

	Fort Frances	Western	Northern	Eastern
Storage	1.2255	1.2231	1.6107	1.9235
Storage - Price Adjustment (1)	(0.0275)	(0.0275)	(0.0275)	(0.0275)
Commodity and Fuel	31.7996	32.1383	32.5935	32.9687
Commodity and Fuel - Price Adjustment (1)	(9.8875)	(9.8875)	(9.8875)	(9.8875)
Transportation	2.6378	2.6488	3.2384	3.7443
Transportation - Price Adjustment (1)	(0.7675)	(0.7675)	(0.7675)	(0.7675)
Total Gas Supply Charge	24.9804	25.3278	26.7602	27.9540

Notes:
(1) As laid out in Appendix A. The Commodity and Fuel line includes gas supply administration charge of 0.3173 cents/m^3.

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Union Gas Limited
Northern and Eastern Operations Area
Gas Supply Charges

Utility Sales

	Fort Frances	Western	Northern	Eastern
Rate 20 (cents / m^3)				
Effective July 1, 2007				
Commodity and Fuel	32.1780	32.5207	32.9813	33.3611
Commodity and Fuel - Price Adjustment (1)	(9.8875)	(9.8875)	(9.8875)	(9.8875)
Commodity Transportation - Charge 1	2.1365	2.1400	2.5308	2.8583
Transportation 1 - Price Adjustment (1)	(0.2215)	(0.2215)	(0.2215)	(0.2215)
Commodity Transportation - Charge 2	0.1259	0.1236	0.1909	0.2508
Monthly Gas Supply Demand	24.4742	24.7073	41.3066	55.1752
Gas Supply Demand - Price Adjustment (1)	0.7275	0.7275	0.7275	0.7275
Commissioning and Decommissioning Rate	3.2143	3.2319	4.6495	5.8354
Rate 100 (cents / m^3)				
Effective July 1, 2007				
Commodity and Fuel	32.1780	32.5207	32.9813	33.3611
Commodity and Fuel - Price Adjustment (1)	(9.8875)	(9.8875)	(9.8875)	(9.8875)
Commodity Transportation - Charge 1	3.7489	3.7515	4.0447	4.2903
Commodity Transportation - Charge 2	0.1259	0.1236	0.1909	0.2508
Monthly Gas Supply Demand	39.1286	39.4005	58.7664	74.9465
Commissioning and Decommissioning Rate	3.5164	3.5289	4.6026	5.5020
Rate 25 (cents / m^3)				
Effective July 1, 2007				
Gas Supply Charge: Interruptible Service				
Minimum	14.3135	14.3135	14.3135	14.3135
Maximum	140.5622	140.5622	140.5622	140.5622

Notes:
(1) As laid out in Appendix A. The Commodity and Fuel line includes gas supply administration charge of 0.3173 cents/m^3.

Effective: July 1, 2007
O.E.B. Order # EB-2007-0598

Chatham, Ontario

Supersedes EB-2007-0053 Rate Schedule effective April 1, 2007.

unionGas

RATE 01A – SMALL VOLUME GENERAL FIRM SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end user whose total gas requirements at that location are equal to or less than 50,000 m^3 per year.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For continuous supply of natural gas by Union and associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For continuous delivery on Union's distribution system from the Point of Receipt on TCPL's system to the Point of Consumption on the customer's premises of natural gas owned by the customer and transported by TCPL under a firm transportation service tariff or equivalent National Energy Board Order. For this service, the Monthly and Delivery Charges shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems.

(c) **Bundled Transportation Service**

For continuous delivery by Union of gas owned by the customer and for the associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service the Monthly, and Delivery Charges, as well as the Storage and Transportation Charges of the Gas Supply Charge shall apply.

MONTHLY RATES AND CHARGES

Zone	Fort Frances	Western	Northern	Eastern
Rate Schedule No.	201	101	301	601
	APPLICABLE TO ALL SERVICES			
MONTHLY CHARGE	$16.00	$16.00	$16.00	$16.00
DELIVERY CHARGE	¢ per m^3	¢ per m^3	¢ per m^3	¢ per m^3
First 100 m^3 per month @	9.2380	9.2380	9.2380	9.2380
Next 200 m^3 per month @	8.6369	8.6369	8.6369	8.6369
Next 200 m^3 per month @	8.2100	8.2100	8.2100	8.2100
Next 500 m^3 per month @	7.8180	7.8180	7.8180	7.8180
Over 1,000 m^3 per month @	7.4944	7.4944	7.4944	7.4944
Delivery- Price Adjustment (All Volumes)	0.3146	0.3146	0.3146	0.3146

ADDITIONAL CHARGES FOR SALES SERVICE

GAS SUPPLY CHARGES

Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

MONTHLY BILL

The monthly bill will equal the sum of the monthly charges plus the rates multiplied by the applicable gas quantities delivered plus all applicable taxes. If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall be the Monthly Charge.

DELAYED PAYMENT

When payment of the monthly bill has not been made in full 16 days after the bill has been issued, the unpaid balance including previous arrears shall be increased by 1.5%.

SERVICE AGREEMENT

Customers providing their own gas supply in whole or in part, for transportation by Union, must enter into a Service Agreement with Union.

TERMS AND CONDITIONS OF SERVICE

1. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, possibly for a fee, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the quantities or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the monthly billing data of individual end-users to generate a single bill which is less than the sum of the monthly bills of the individual end-users involved at each location.

2. Customers must enter into a Service Agreement with Union prior to the commencement of service.

3. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

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RATE 10 – LARGE VOLUME GENERAL FIRM SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end-user whose total firm gas requirements at one or more Company-owned meters at one location exceed 50,000 m^3 per year.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For continuous supply of natural gas by Union and associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For continuous delivery on Union's distribution system from the Point of Receipt on TCPL's system to the Point of Consumption on the customer's premises of natural gas owned by the customer and transported by TCPL under a firm transportation service tariff or equivalent National Energy Board Order. For this service, the Monthly, and Delivery Charges shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems. Customers may reduce their assignment of transportation capacity in compliance with Union's Turnback Policy.

(c) **Bundled Transportation Service**

For continuous delivery by Union of gas owned by the customer and for the associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service the Monthly, and Delivery Charges, as well as the Storage and Transportation Charges of the Gas Supply Charge shall apply.

MONTHLY RATES AND CHARGES

Zone Rate Schedule No.	Fort Frances 210	Western 110	Northern 310	Eastern 610
	APPLICABLE TO ALL SERVICES			
MONTHLY CHARGE	\$70.00	\$70.00	\$70.00	\$70.00
DELIVERY CHARGE	¢ per m^3	¢ per m^3	¢ per m^3	¢ per m^3
First 1,000 m^3 per month @	7.3562	7.3562	7.3562	7.3562
Next 9,000 m^3 per month @	5.8543	5.8543	5.8543	5.8543
Next 20,000 m^3 per month @	4.9979	4.9979	4.9979	4.9979
Next 70,000 m^3 per month @	4.4495	4.4495	4.4495	4.4495
Over 100,000 m^3 per month @	2.3725	2.3725	2.3725	2.3725
Delivery-Price Adjustment (All Volumes)	0.4646	0.4646	0.4646	0.4646

ADDITIONAL CHARGES FOR SALES SERVICE

GAS SUPPLY CHARGES

Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

MONTHLY BILL

The monthly bill will equal the sum of the monthly charges plus the rates multiplied by the applicable gas quantities delivered plus all applicable taxes. If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply.

MINIMUM MONTHLY BILL

The minimum monthly bill shall be the Monthly Charge.

DELAYED PAYMENT

When payment of the monthly bill has not been made in full 16 days after the bill has been issued, the unpaid balance including previous arrears shall be increased by 1.5%.

SERVICE AGREEMENT

Customers providing their own gas supply in whole or in part, for transportation by Union and customers purchasing gas from Union with maximum daily requirements in excess of 3,000 m^3 per day must enter into a Service Agreement with Union.

TERMS AND CONDITIONS OF SERVICE

1. Service shall be for a minimum term of one year.

2. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, possibly for a fee, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the quantities or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the monthly billing data of individual end-users to generate a single bill which is less than the sum of the monthly bills of the individual end-users involved at each location.

3 Customers must enter into a Service Agreement with Union prior to the commencement of service.

4. For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

5. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

Effective
2007-07-01
Schedule "A"

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Gas Supply Charges

(A) Availability:

Available to customers in Union's Southern Delivery Zone.

(B) Applicability:

To all sales customers served under rates M2, M4, M5A, M7, M9, M10 and storage and transportation customers taking supplemental services under rates T1 and T3.

(C) Rates:

	cents / m^3
Utility Sales	
Commodity and Fuel	32.9687 (1)
Commodity and Fuel - Price Adjustment	(7.0317)
Transportation	3.6279
Total Gas Supply Commodity Charge	29.5649
Minimum Annual Gas Supply Commodity Charge	
Rate M4 Firm and Rate M5A Interruptible Contract	5.5663
Storage and Transportation Supplemental Services - Rate T1 & T3	$/GJ
Monthly demand charges:	
Firm gas supply service	28.065
Firm backstop gas	4.245
Commodity charges:	
Gas supply	8.788
Backstop gas	11.727
Reasonable Efforts Backstop Gas	11.404
Supplemental Inventory	Note (2)
Supplemental Gas Sales Service (cents / m^3)	46.4836
Failure to Deliver: Applied to quantities not delivered to Union in the event the customer's supply fails	3.011
Discretionary Gas Supply Service (DGSS)	Note (3)

Notes:

(1) The Commodity and Fuel line includes gas supply administration charge of 0.3173 cents/ m^3.
(2) The charge for banked gas purchases shall be the higher of the daily spot gas cost at Dawn in the month of or the month following the month in which gas is sold under this rate and shall not be less than Union's approved weighted average cost of gas.
(3) Reflects the "back to back" price plus gas supply administration charge.

Effective: July 1, 2007
O.E.B. Order # EB-2007-0598

Chatham, Ontario

Supersedes EB-2007-0053 Rate Schedule effective April 1, 2007.

GENERAL SERVICE RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To residential and non-contract commercial and industrial customers.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

a) Monthly Charge $ 16.00

b) Delivery Charge

First	1 400 m^3	5.1701¢ per m^3
Next	4 600 m^3	4.1427¢ per m^3
Next	124 000 m^3	3.0859¢ per m^3
Next	270 000 m^3	2.4743¢ per m^3
All Over	400 000 m^3	2.2978¢ per m^3

Delivery – Price Adjustment (All Volumes) 0.2194¢ per m^3

c) Storage Charge (if applicable) 0.9309¢ per m^3

Applicable to all bundled customers (sales and bundled transportation service).

d) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

During any month in which a customer terminates service or begins service, the fixed charge for the month will be prorated to such customer.

(D) Supplemental Service to Commercial and Industrial Customers Under Group Meters

Combination of readings from several meters may be authorized by the Company and the Company will not reasonably withhold authorization in cases where meters are located on contiguous pieces of property of the same owner not divided by a public right-of-way. In such cases, an additional service charge shall be rendered each month in the amount of $15.00 per month for each additional meter so combined.

(E) Delayed Payment

When payment of the monthly bill has not been made in full 16 days after the bill has been issued, the unpaid balance including previous arrears shall be increased by 1.5%.

(F) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(G) Overrun Charge

In the event that a direct purchase customer fails to deliver its contracted volumes to Union, and Union has the capability to continue to supply the customer, Union will do so. The customer may pay 6.1010¢ per m^3 for the delivery and the total gas supply charge for utility sales provided in Schedule "A" per m^3, plus 7¢ per m^3.

(H) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule, the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union. Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

(I) Company Policy Relating to Terms of Service

a. Customers who temporarily discontinue service during any twelve consecutive months without payment of the monthly fixed charge for the months in which the gas is temporarily disconnected shall pay for disconnection and reconnection.

b. When gas is delivered at an absolute pressure in excess of 101.325 kilopascals, then for purposes of measurement, hereunder, such volume of gas shall be corrected to an absolute pressure of 101.325 kilopascals. Atmospheric pressure is assumed to be the levels shown below in kilopascals (absolute) regardless of the actual atmospheric pressure at which the gas is measured and delivered.

Zone	Assumed Atmospheric Pressure kPa
1	100.148
2	99.494
3	98.874
4	98.564
5	98.185
6	97.754
7	97.582
8	97.065
9	96.721
10	100.561
11	99.321
12	98.883

Unit Rates for Prospective Recovery / (Refund), One-time Adjustments, and Storage and Transportation (Ex-Franchise) Balances for Disposition

UNION GAS LIMITED
General Service Rates
Unit Rates for Prospective Recovery/(Refund): Delivery

Line No.	Particulars	Rate Class	2006 Deferral Balances ($000's)	2006 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2007 Forecast Volume (10*3m*3) (1)	Unit Rate for Prospective Recovery (cents/m*3)
			(a)	(b)	(c)= (a) + (b)	(d)	(e) = (c) / (d) * 100
1	Small Volume General Service	01	3,558	(2,458)	1,100	349,669	0.3146
2	Large Volume General Service	10	1,126	(402)	724	155,907	0.4646
3	General Service	M2	10,868	(6,028)	4,839	1,543,695	0.3135

Notes:
(1) Forecast volume for the period July 1, 2007 to December 31, 2007

UNION GAS LIMITED
General Service Rates
Unit Rates for Prospective Recovery/(Refund): Gas Supply Transportation

Line No.	Particulars	Rate Class	2006 Deferral Balances ($000's)	2006 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2007 Forecast Volume (10*3m*3) (1)	Unit Rate for Prospective Recovery (cents/m*3)
			(a)	(b)	(c)= (a) + (b)	(d)	(e) = (c) / (d) * 100
1	Small Volume General Service	01	(2,529)	-	(2,529)	349,669	(0.7232)
2	Large Volume General Service	10	(1,011)	-	(1,011)	154,329	(0.6551)

Notes:
(1) Forecast volume for the period July 1, 2007 to December 31, 2007

EB-2007-0598
Appendix C
Schedule 3

UNION GAS LIMITED
Sales Service Rates
Unit Rates for Prospective Recovery/(Refund): Gas Supply Commodity

Line No.	Particulars	2006 Deferral Balances ($000's)	2006 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2007 Forecast Volume (10*3m*3) (1)	Unit Rate for Prospective Recovery (cents/m*3)
		(a)	(b)	(c)= (a) + (b)	(d)	(e) = (c) / (d) * 100
1	Sales Service	486	-	486	885,507	0.0549

Notes:
(1) Forecast volume for the period July 1, 2007 to December 31, 2007

UNION GAS LIMITED
Unit Rates for One-Time Adjustments

Line No.	Particulars	Rate Class	2006 Deferral Balances ($000's) (a)	2006 Earnings Sharing ($000's) (b)	Total Balance ($000's) (c)= (a) + (b)	2006 Actual Volume (10*3m*3) (d)	Unit Rate (cents/m*3) (e) = (d)/ (c) * 100
	Northern and Eastern Operations Area:						
1	Medium Volume Firm Service (1)	20	270	(45)	225	168,163	0.1338
2	Medium Volume Firm Service (2)	20T	754	(86)	667	323,278	0.2065
3	Large Volume High Load Factor (2)	100T	1,866	(331)	1,535	2,085,761	0.0736
4	Wholesale Service	77	0.03	(0)	(0)	92	(0.4892)
5	Large Volume Interruptible	25	7	(124)	(117)	234,980	(0.0499)
	Southern Operations Area:						
6	Firm Com/Ind Contract	M4	1,852	(242)	1,610	536,254	0.3003
7	Interruptible Com/Ind Contract	M5	1,133	(149)	983	518,036	0.1898
8	Special Large Volume Contract	M7	1,200	(212)	988	765,164	0.1291
9	Large Wholesale	M9	8	(9)	(1)	18,758	(0.0052)
10	Small Wholesale	M10	(1)	(1)	(1)	102	(1.3883)
11	Contract Carriage Service	T1	(984)	(443)	(1,427)	3,445,763	(0.0414)
12	Contract Carriage- Wholesale	T3	(452)	(70)	(522)	267,368	(0.1953)

Notes:
(1) Sales and Bundled-T customers only
(2) T-service customers only

UNION GAS LIMITED
Unit Rates for One-Time Adjustments: Gas Supply Transportation and Bundled Storage

Line No.	Particulars	Rate Class	Billing Units	2006 Deferral Balances ($000's) (a)	2006 Earnings Sharing ($000's) (b)	Total Balance ($000's) (c)= (a) + (b)	2006 Actual Demand (d)	Unit Demand Rate (e) = (d)/ (c) * 100
	Gas Supply Transportation (cents/m*3)							
1	Medium Volume Firm Service	20	10*3m*3	(59)	-	(59)	8,610	(0.6883)
	Bundled (T- Service) Storage ($/GJ)							
2	Medium Volume Firm Service	20T	GJ	(5)	-	(5)	9,352	(0.587)
3	Large Volume High Load Factor	100T	GJ	(85)	-	(85)	144,628	(0.587)

UNION GAS LIMITED
Summary of 2006 Earnings Sharing and 2006 Deferral Account Disposition
Storage and Transportation Services

Line No.	Particulars ($000's) (1)	Rate Class	2006 Deferral Balances ($000's)	2006 Earnings Sharing ($000's)	Total Balance ($000's)
			(a)	(b)	(c) = (a + b)
1	Storage and Transportation	M12	(2,530)	(2,240)	(4,770)
2	Local Production	M13	183	(2)	181
3	Short-Term Cross Franchise	C1	306	(32)	274
4	Storage Transportation Service	M16	55	(3)	52

Note: (1) Exfranchise M12, M13, M16 and C1 customers based on specific amounts determined using approved deferral account allocation methodologies.

UNION GAS LIMITED
Southern Operations Area
Calculation of Gas Supply Commodity Charges

Line No.	Particulars	EB-2007-0053 Effective April 1, 2007 (cents/m³)	($/GJ) (1)	EB-2007-0598 Effective July 1, 2007 (cents/m³)	($/GJ) (2)		Change Effective July 1, 2007 (cents/m³)		($/GJ)
		(a)	(b)	(c)	(d)		(e)= (c) - (a)		(f)= (d) - (b)
1	Alberta Border Price	31.0303	8.288	31.0303	8.288	(3)	-		-
2	Fuel Ratios	5.224%	5.224%	5.224%	5.224%		0.000%		0.000%
3	Compressor Fuel Charge	1.6211	0.433	1.6211	0.433		-		-
4	Administration Charge	0.3173	0.085	0.3173	0.085		-		-
5	Gas Commodity & Fuel Rate (line 1+3+4)	32.9687	8.806	32.9687	8.806		-		-
	Prospective Recovery								
6	Inventory Revaluations	1.2159	0.325	1.2159	0.325		-		-
7	Spot Gas	0.0001	-	0.0001	-		-		-
8	Firm PGVA	(8.3026)	(2.218)	(8.3026)	(2.218)		-		-
9	Commodity Temporary Charge/(Credit) - Jul 1-Dec 31, 2007	-	-	0.0549	0.015		0.0549	(4)	0.015
10	Prospective Recovery (line 6+7+8+9)	(7.0866)	(1.893)	(7.0317)	(1.8780)		0.0549		0.0150
11	Total Commodity and Fuel Rate (line 5+10)	25.8821	6.913	25.9370	6.928		0.0549		0.015
12	Transportation Tolls	3.6279	0.969	3.6279	0.969	(5)	-		-
13	Total Commodity & Fuel & Transportation Rate (line 11+12)	29.5100	7.882	29.5649 (6)	7.897		0.0549		0.015

Notes:
(1) Conversion to GJs based on avg. heating value of Western suppliers of 37.63 GJs / 10^3m^3.
(2) Conversion to GJs based on avg. heating value of Western suppliers of 37.44 GJs / 10^3m^3.
(3) Alberta Border price per EB-2007-0053, Tab 1, Schedule 1, Line 11.
(4) Commodity temporary charge of 0.0549 cents/m³ for the period Jul 1-Dec 31, 2007.
(5) EB-2007-0053, Tab 1, Schedule 2, Line 6
(6) Appendix A, Page 6, Line 4, Column (c)